IMPACT ANALYSIS of Basic SOFA with SNCR ALTERNATIVE for LELAND OLDS UNIT 1

This document is being provided in response to the North Dakota Department of Health's request issued in a December 1, 2006 letter to Basin Electric Power Cooperative regarding the NDDH's comments from their review of the final draft report of the BEPC LOS BART DETERMINATION STUDY for LELAND OLDS STATION UNIT 1 and 2 (August 2006).

This is intended to be in addition to the following sections:

2.4.2 Energy Impacts of NO_X Control Alternatives – LOS Unit 1;

2.4.3 Non Air Quality and Other Environmental Impacts of NO_X Control Alternatives – LOS Unit 1;

2.4.4 Visibility Impairment Impacts of Leland Olds Station NO_X Controls – Unit 1;

2.4.5 Summary of Impacts of LOS NO_X Controls – Unit 1;

CORRECTIONS:

Included in this document are replacements to the following sections of the August 2006 BEPC BART Determination Study report:

2.4.1.2 Operating and Maintenance Cost Estimates for NO_X Controls – LOS Unit 1;

2.4.1.3 Cost Effectiveness for NO_X Controls – LOS Unit 1;

The following describes corrections to Section 2.4.1.2 O&M costs, and Section 2.4.1.3 Cost Effectiveness, for those LOS Unit 1 alternatives that involve a chemical reagent injected for NOx control. These corrections are included in front of the updated impacts evaluation added for the basic SOFA with SNCR NO_X Control alternative for LOS Unit 1.

Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water should be included in the O&M costs; this follows EPA OAQPS convention. For the purposes of this study, this additional coal consumption has been included in the annual O&M costs provided in the August 2006 final draft of the BEPC LOS BART Report. For example, the cost of this extra coal consumption was incorrectly calculated as $10 per year for LOS Unit 1's basic SOFA + SNCR alternative for both the historic and PTE cases in the August 2006 final draft of the BEPC LOS BART Report, assuming $0.91/mmBtu. It should have been 53,645 mmBtu/yr x $0.91/mmBtu = $48,600/yr annual O&M cost for LOS Unit 1's basic SOFA + SNCR alternative.

Similarly, included in this document are replacements to the following sections of the August 2006 BEPC BART Determination Study report:

2.5.1.2 Operating and Maintenance Cost Estimates for NO_X Controls – LOS Unit 2;

2.5.1.3 Cost Effectiveness for NO_X Controls – LOS Unit 2;

The following describes corrections to Section 2.5.1.2 O&M costs, and Section 2.5.1.3 Cost Effectiveness, for those LOS Unit 2 alternatives that involve a chemical reagent injected for NO_X control. These corrections are also included at the back of this updated impacts evaluation.

The cost of this extra coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water was incorrectly calculated as $20 per year for LOS Unit 2’s SNCR + ASOFA alternative and $40 per year for RRI+SNCR with ASOFA alternative for both the historic and PTE cases in the August 2006 final draft of the BEPC LOS BART Report, assuming $0.91/mmBtu. It should have been 204,807 mmBtu/yr x $0.91/mmBtu = $185,400/yr annual O&M cost for LOS Unit 2’s SNCR + ASOFA alternative, and 389,490 mmBtu/yr x $0.91/mmBtu = $352,700/yr annual O&M cost for LOS Unit 2’s RRI+SNCR with ASOFA alternative.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study report)

2.4.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 1

The operation and maintenance costs to implement the NO_X control technologies evaluated for LOS Unit 1 were largely estimated from cost factors established in the EPA's Air Pollution Control Cost Manual[1] (OAQPS), and from engineering judgment applied to that control technology. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.4-3 and Table 2.4-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the NO_X control options evaluated for LOS Unit 1. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors. The annual operating and maintenance costs of the control options in Table 2.4-3 is based on LOS Unit 1 operation with the control options at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit pre-control baseline operation at 0.285 lb/mmBtu for the highest 24-month NOx emission summation at 2,443 mmBtu/hr heat input for 8,510 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

[1] See Basin LOS BART Determination Study report NO_X Section Reference number 49.

TABLE 2.4-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

NO_X Control Alternative	Annual O&M Cost[1] ($1,000)	Levelized Annual O&M Cost[2] ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,518	3,004
SNCR (using urea) w/ basic SOFA	2,142	2,556
SNCR (using urea) w/ CCOFA	2,461	2,936
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072[3]	3,665[3]
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420[3]	2,887[3]
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

The annual operating and maintenance costs of the control options in Table 2.4-4 are based on LOS Unit 1 operation with the control option at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit baseline operation at 0.29 lb/mmBtu for the highest 24-month NO_X emission summation at 2,622 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

TABLE 2.4-4 – Estimated O&M Costs for NO_X Control Options (Relative to Presumptive BART Annual Emission Baseline – Future PTE Case) LOS Unit 1

NO_X Control Alternative	Annual O&M Cost(1) ($1,000)	Levelized Annual O&M Cost(2) ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,518	3,004
SNCR (using urea) w/ basic SOFA	2,142	2,556
SNCR (using urea) w/ CCOFA	2,461	2,936
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072(3)	3,665(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420(3)	2,887(3)
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.4.1.3 COST EFFECTIVENESS FOR NO_X CONTROLS – LOS UNIT 1

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART determination process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of each alternative, was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 for cost methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. There are two different NO_X emission baselines; the first assumes the highest historic 24-month average NO_X emission rate expressed in tons per year. The second baseline derives tons per year from the maximum future PTE case average NO_X emission rate.

This approach results in two different average cost effectiveness values for the control options evaluated for LOS Unit 1. The annual NO_X emission reduction is the difference between the pre-control baseline and post-control emissions in tons per year. Average control cost for a particular technology is LTAC divided by annual tons of expected emission reduction. A summary of the annual emissions, reductions, control and levelized annual costs for the two LOS Unit 1 baselines are presented in Table 2.4-5 and 2.4-6.

TABLE 2.4-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
G	Coal Reburn with boosted SOFA (future PTE case)	1,666	1,301	7,032(5)	5,404(5)
F	Coal Reburn with basic SOFA (future PTE case)	1,746	1,221	5,983(5)	4,898(5)
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,782	1,185	3,819	3.223
D	SNCR with basic SOFA (future PTE case)	1,883	1,084	3,099	2,858
C	SNCR with Close-Coupled OFA (future PTE case)	2,450	517	3,361	6,504
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,483	484	1,137	2,347
A	Separated Overfire Air (SOFA, basic)	2,642	325	144	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	2,967	0	0	

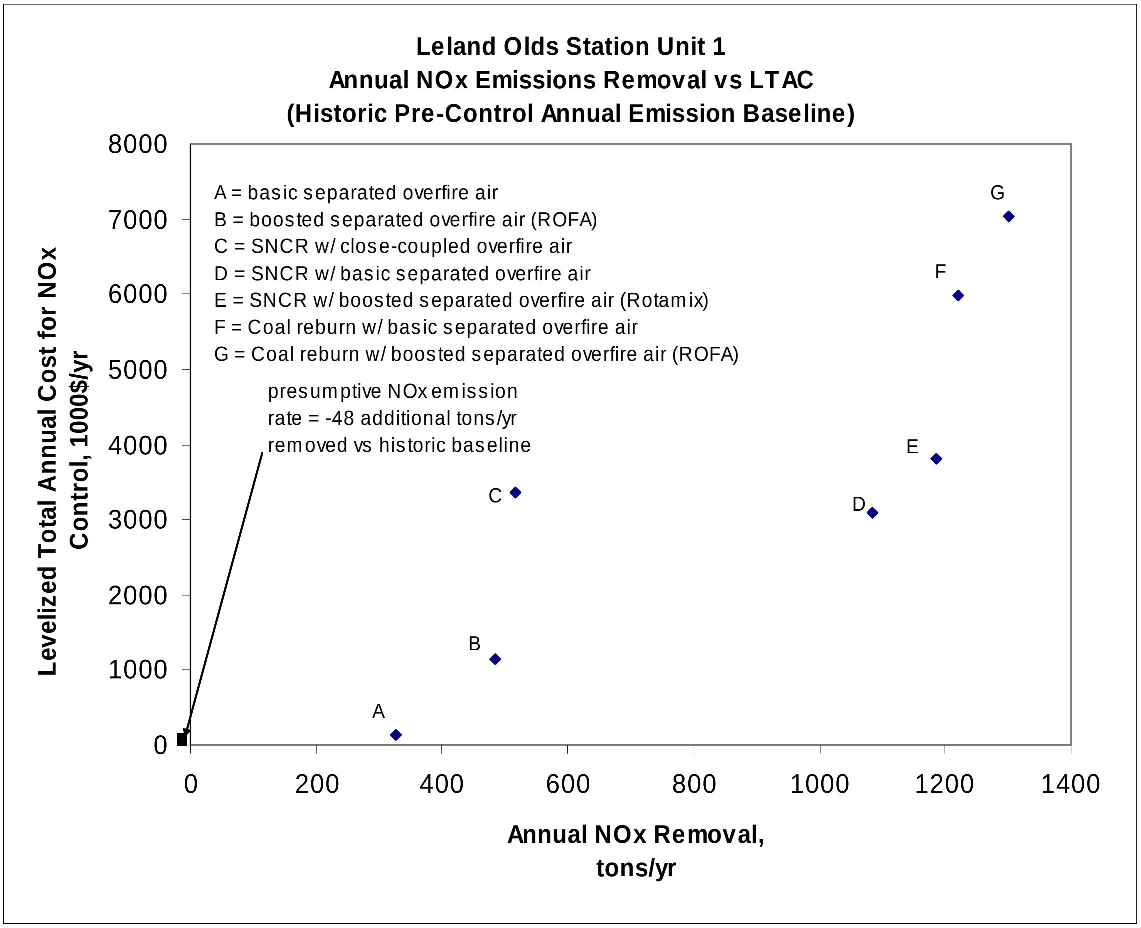
(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – NO_X emissions and control level reductions relative to the highest historic 24-month average pre-control annual baseline for LOS Unit 1.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,762/ton with boosted SOFA and $1,870/ton with basic SOFA.

TABLE 2.4-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Presumptive BART Annual Emission Baseline – Future PTE Case)
LOS Unit 1

Alt. No.[1]	NO_X Control Alternative	Annual NO_X Emissions[2] Tons/yr	Annual NO_X Emissions Reduction[2] Tons/yr	Levelized Total Annual Cost[3],[4] $1,000	Average Control Cost[4] $/ton
G	Coal Reburn with boosted SOFA (future PTE case)	1,693	1,638	7,032[5]	4,293[5]
F	Coal Reburn with basic SOFA (future PTE case)	1,774	1,557	5,983[5]	3,844[5]
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,811	1,519	3,819	2,513
D	SNCR with basic SOFA (future PTE case)	1,913	1,417	3,099	2,187
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,469	862	1,137	1,319
B	SNCR with Close-Coupled OFA (future PTE case)	2,490	841	3,362	4,000
A	Separated Overfire Air (SOFA, basic)	2,641	689	144	208
	Baseline, based on annual operation at future PTE scenario pre-control emission rate	3,330	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE scenario applied to LOS Unit 1.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-4 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,493/ton with boosted SOFA and $1,571/ton with basic SOFA.

Figure 2.4-1 – NO_X Control Cost Effectiveness – LOS Unit 1 (Historic Pre-Control Annual Emission Baseline)[(1)]



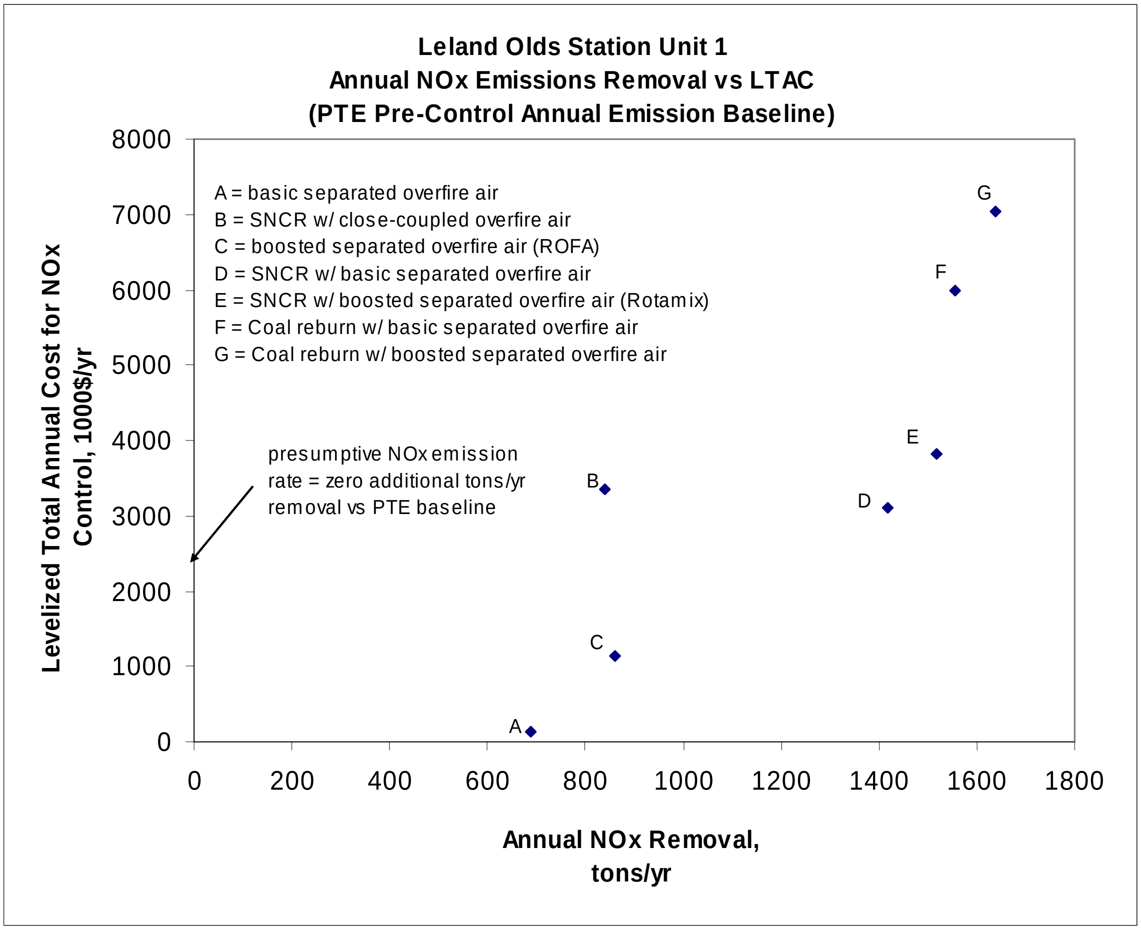
(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 1 relative to two different NO_X emission baselines was made and is shown in Figures 2.4-1 and 2.4-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.4-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 1 under the future PTE case.

Figure 2.4-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit ` under the future PTE case.

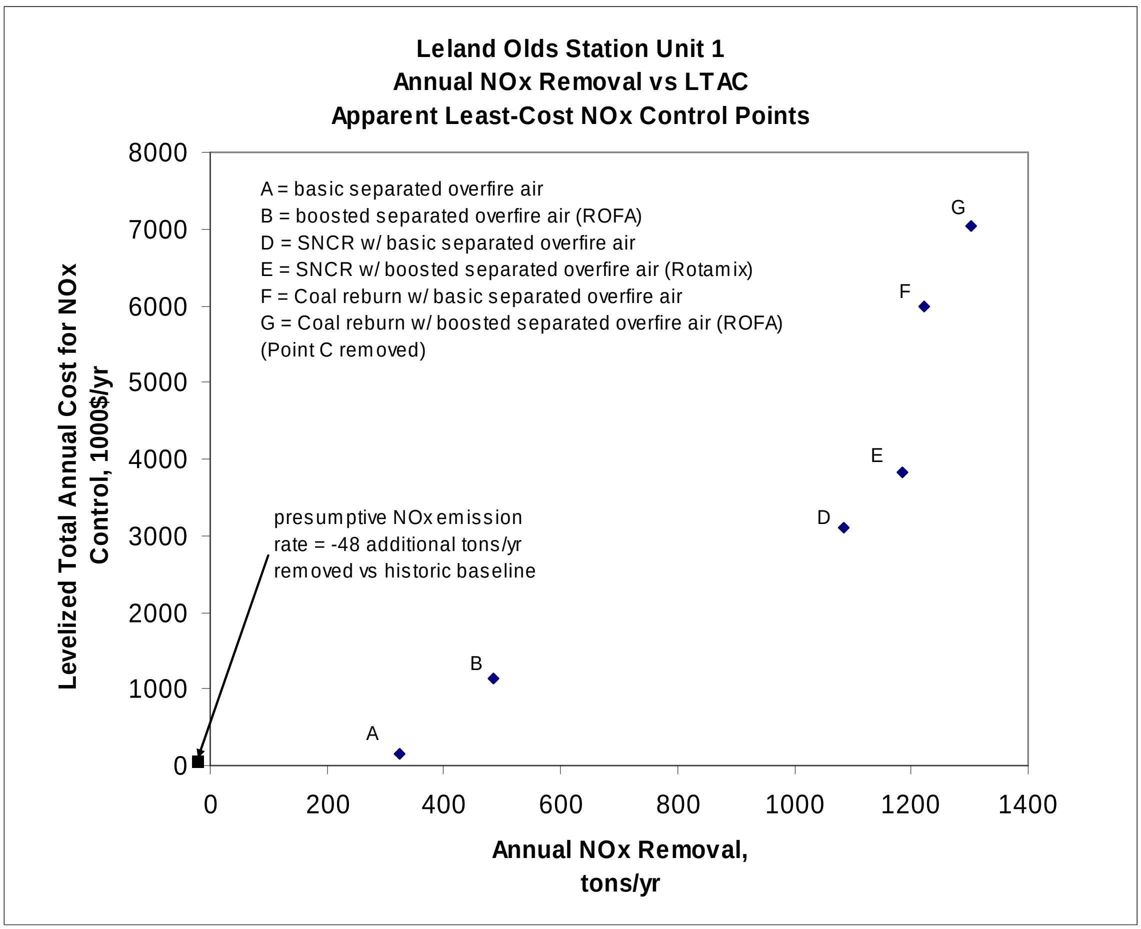
Figure 2.4-2 – NO_X Control Cost Effectiveness – LOS Unit 1 (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

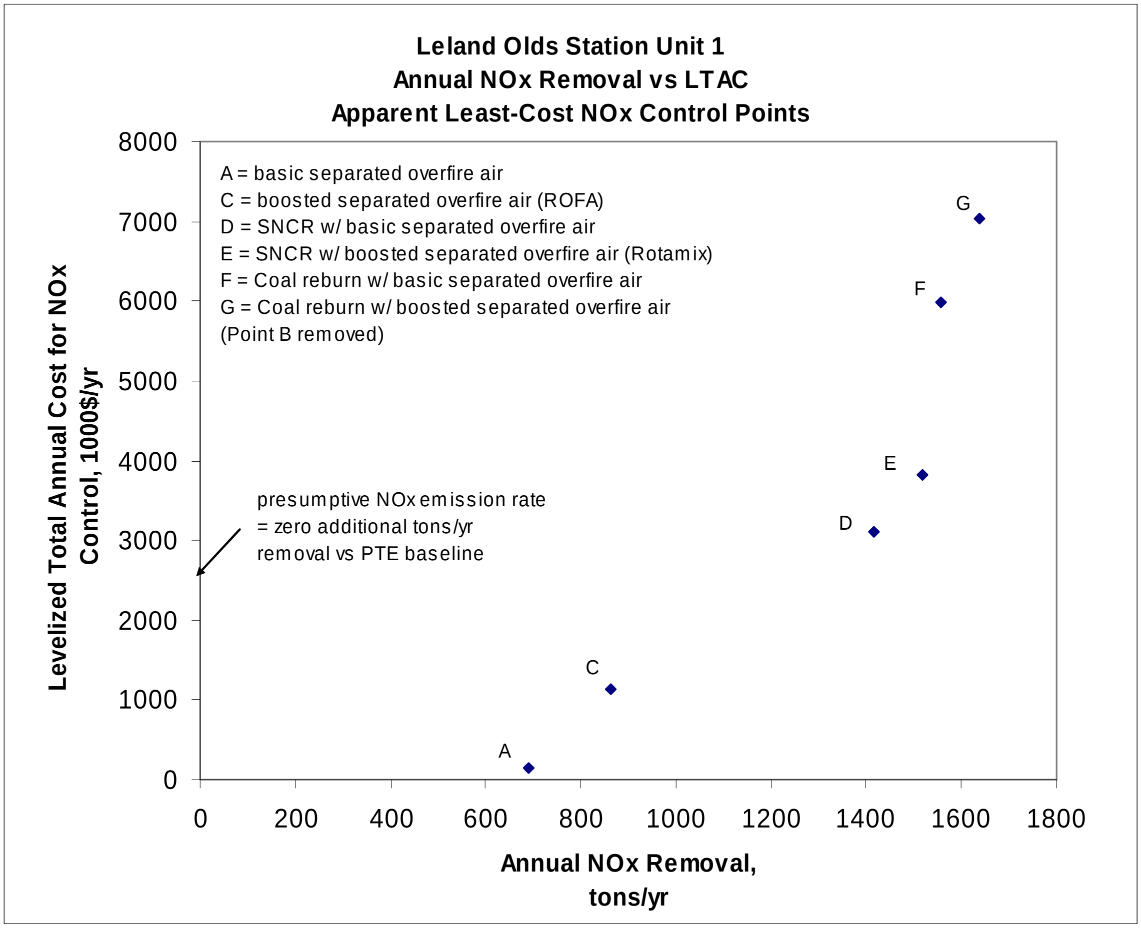
The purpose of Figures 2.4-1 and 2.4-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a “bottom-up” graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 1 NO_X control alternatives evaluated for cost-effectiveness, the data point for SNCR with close-coupled OFA is seen to be more costly for fewer tons of NO_X removed than for boosted separated overfire air (ROFA). SNCR with CCOFA appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis. Figures 2.4-3 and 2.4-4 show the revised least-cost control points without SNCR with CCOFA.

Figure 2.4-3 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost NOx Control Points (Historic Pre-Control Annual Emission Baseline)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

Figure 2.4-4 – NO_X Control Cost Effectiveness – LOS Unit 1
Apparent Least-Cost NOx Control Points
(PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.4-5 and Figure 2.4-6 contain a repetition of the levelized total annual cost and NO_X control information from Figure 2.4-3 and Figure 2.4-4 with SNCR with CCOFA removed (Point C in Figure 2.4-1, and Point B in Figure 2.4-2), and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point.

TABLE 2.4-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	1,049	80	13,130
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,221	2,164	37	58,972
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,185	719	100	7,173
D	SNCR with basic SOFA (future PTE case)	3,099	1,084	1,962	600	2,271
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	484	993	159	6,249
A	Separated Overfire Air (SOFA, basic)	144	325	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

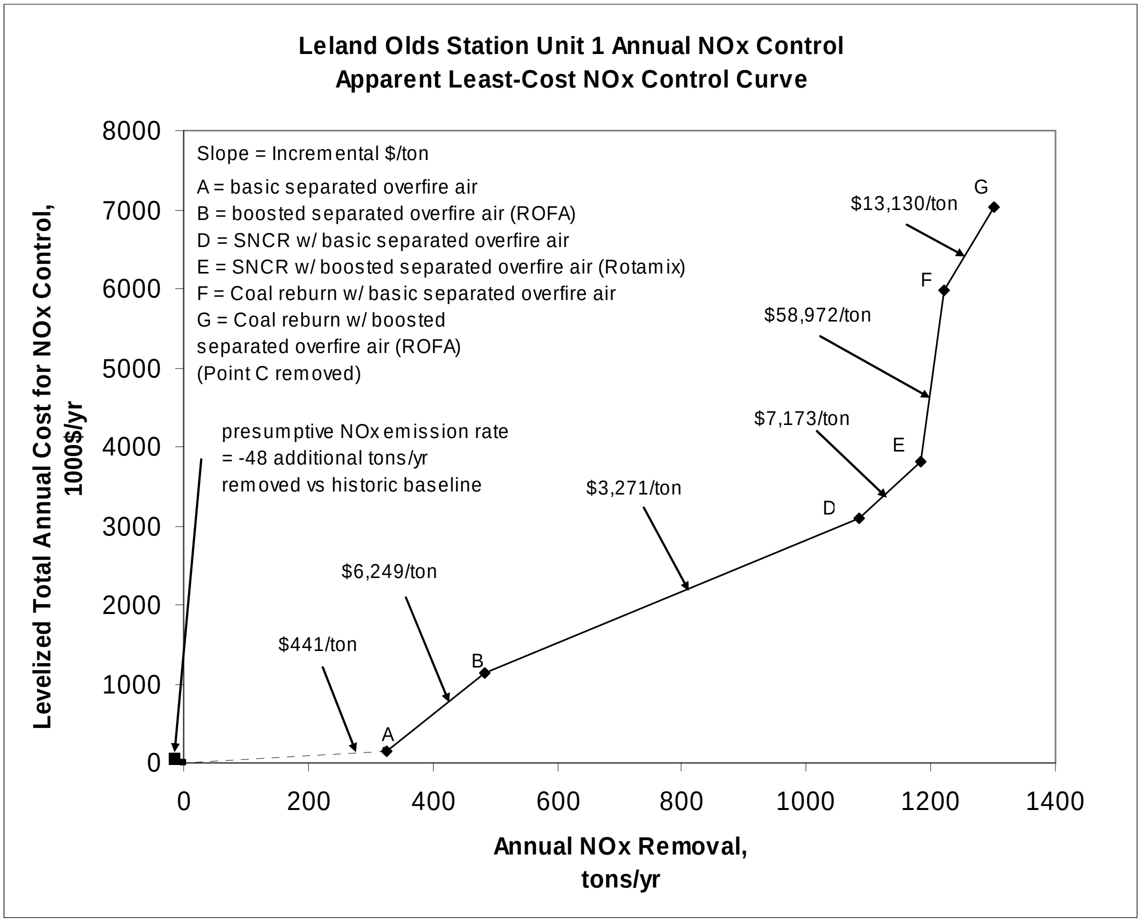
(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors. Costs for increased PM collection efficiency are included in coal reburn options.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 1

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[(2),(3)] ($1,000)	Annual Emission Reduction[(4)] (Tons/yr)	Incremental Levelized Total Annual Cost[(3),(5)] ($1,000)	Incremental Annual Emission Reduction[(4),(5)] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[(3),(6)]
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	1,049	81	12,921
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,557	2,164	37	58,035
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,519	719	102	7,058
D	SNCR with basic SOFA (future PTE case)	3,099	1,417	1,462	556	3,532
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	862	993	172	5,763
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

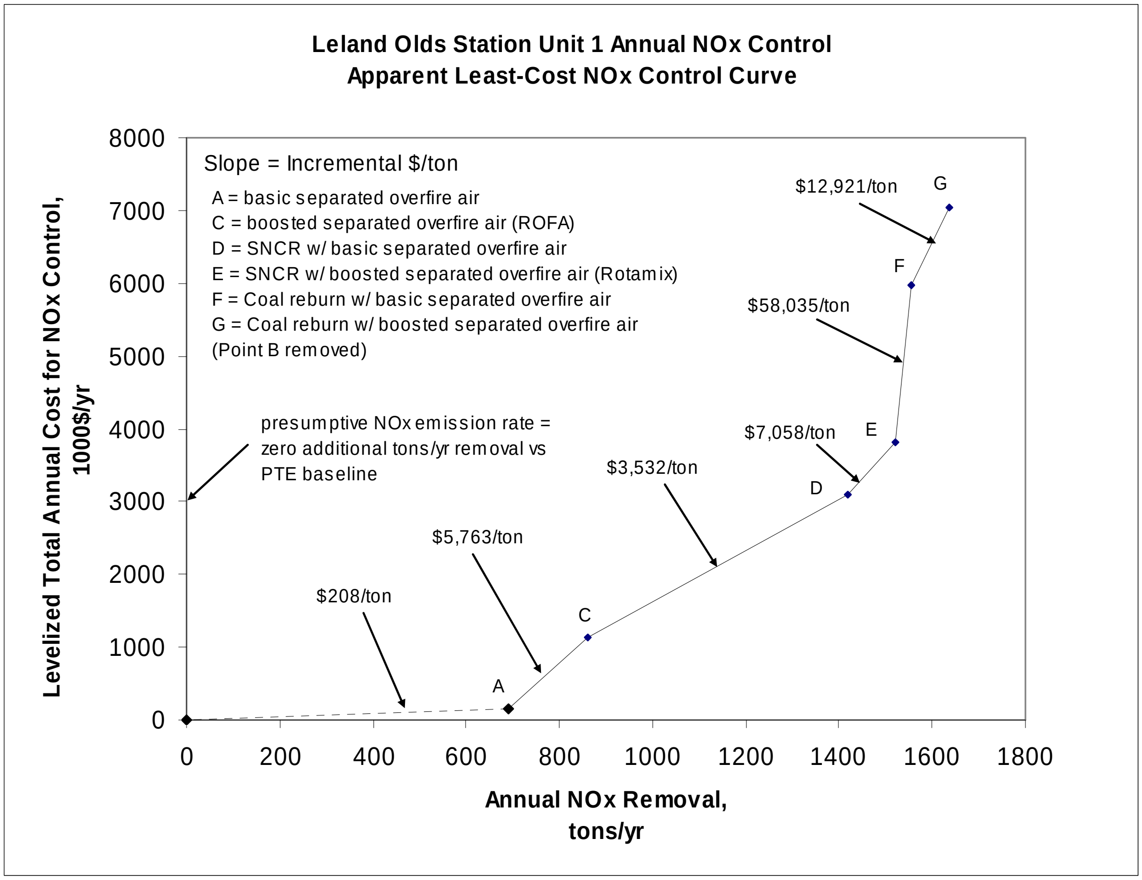
(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn options.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

Figure 2.4-5 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (Historic Pre-Control Annual Emission Baseline)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-7.

Figure 2.4-6 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)[(1)]

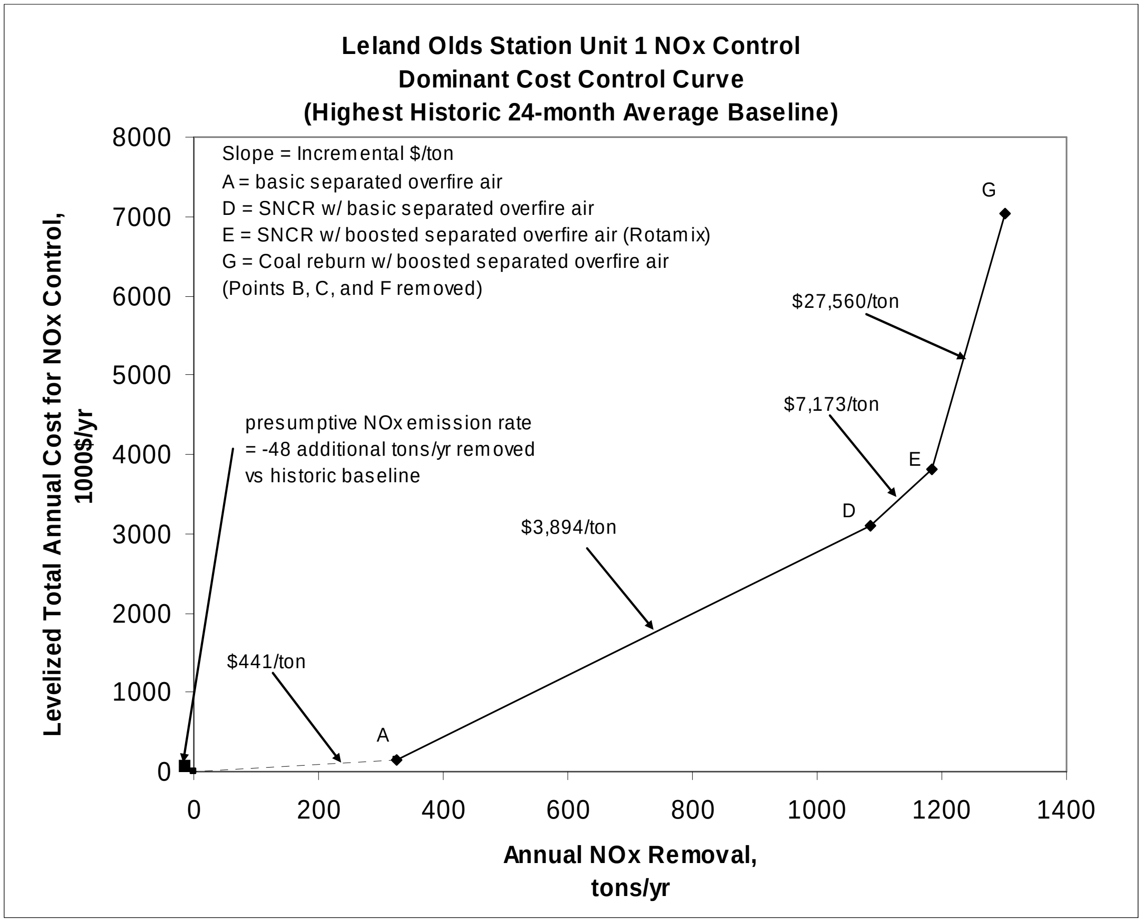


(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-8.

In the comparison displayed in Figure 2.4-5 and Figure 2.4-6, for the data shown in Table 2.4-7 and Table 2.4-8, the boosted SOFA (ROFA) NO_X control alternative (Point B in Figure 2.4-5, Point C in Figure 2.4-6) had a significantly higher incremental unit NO_X control cost (slope, $6,249/ton and $5,763/ton, respectively) compared against basic SOFA alternative (Point A) versus SNCR with basic SOFA (Points D) compared against ROFA. Also, Coal Reburn with basic SOFA (Points F) was significantly more incrementally expensive ($58,972/ton and $58,035/ton) compared against SNCR with boosted SOFA (Points E) versus Coal Reburn with boosted SOFA (Points G) compared against Coal Reburn with basic SOFA alternatives (Point F) ($13,130/ton and $12,921/ton). This indicates that Points C and Points F are inferior controls and do not occupy the Dominant Cost Control Curves.

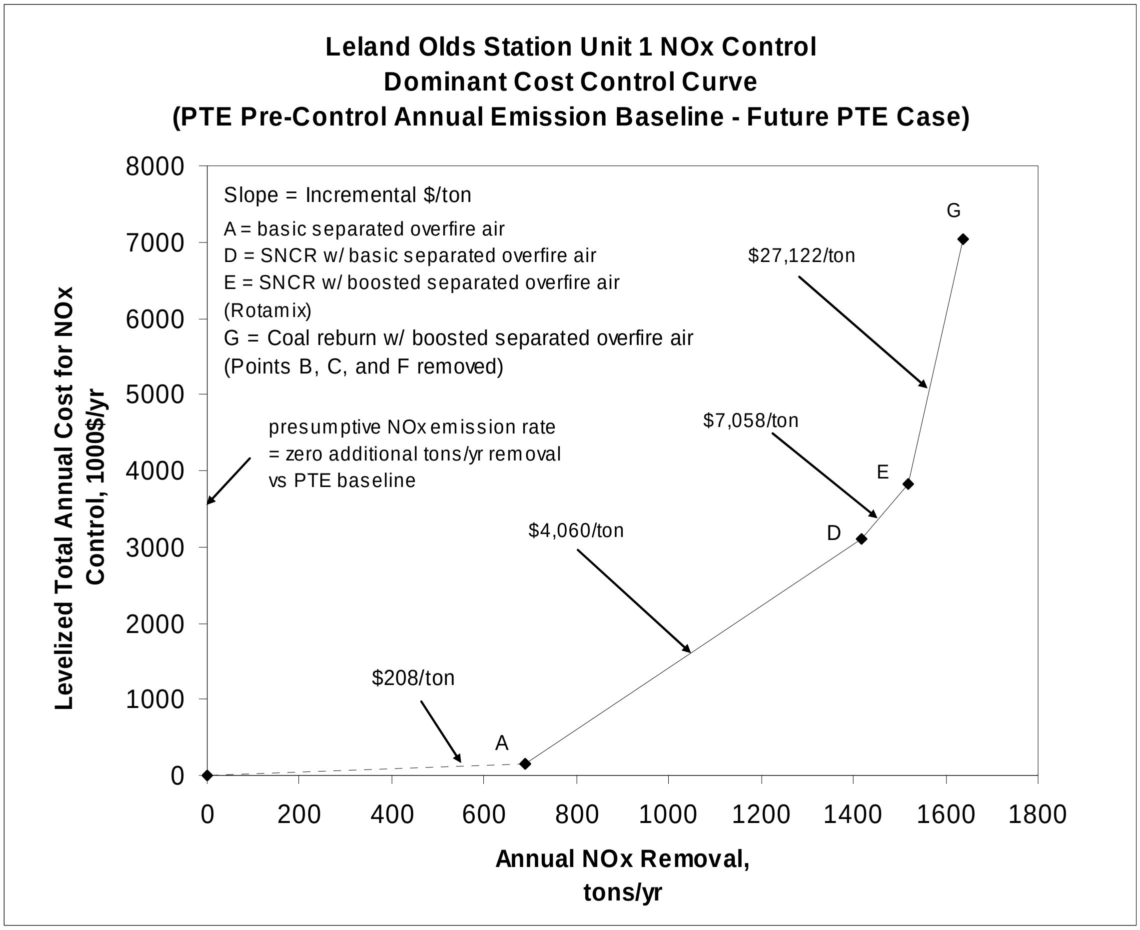
After removal of Points C and F, the modified least-cost controls curve is the Dominant Cost Control Curve for NO_X emissions alternatives for each of the LOS Unit 1 pre-control baselines evaluated.

Figure 2.4-7 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)[1]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-9.

Figure 2.4-8 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve(1) (PTE Pre-Control Annual Emission Baseline – Future PTE Case)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-10.

TABLE 2.4-9 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1 NO_X Control

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	3,213	117	27,560
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,185	719	100	7,173
D	SNCR with basic SOFA (future PTE case)	3,099	1,084	2,956	759	3,894
A	Separated Overfire Air (SOFA, basic)	144	325	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-10 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 1 NO_X Control

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[2],[3] ($1,000)	Annual Emission Reduction[4] (Tons/yr)	Incremental Levelized Total Annual Cost[3],[5] ($1,000)	Incremental Annual Emission Reduction[4],[5] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3],[6]
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	3,213	118	27,122
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,519	719	102	7,058
D	SNCR with basic SOFA (future PTE case)	3,099	1,417	2,956	728	4,060
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors. Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

The cost impact analysis for historic and PTE baseline conditions identifies those control alternatives that are on the Dominant Controls Cost Curve. Those alternatives are scrutinized for cost-effectiveness on both relative and absolute bases. In the comparison displayed in Figure 2.4-7 and Figure 2.4-8, for the data shown in Table 2.5-9 and Table 2.5-10, the SNCR with basic SOFA NO_X control alternative (Points D) had a significantly higher incremental unit NO_X control cost (slope, $3,894/ton and $4,060/ton, respectively, for historic and PTE baseline conditions) compared against basic SOFA alternative (Point A) versus baseline ($441/ton and $208/ton, respectively). The incremental cost-effectiveness of the least-cost SNCR alternative on the Dominant Cost Control Curve is on the order of eight to nineteen times the magnitude of basic SOFA. SNCR with boosted SOFA (Point E) had a significantly higher incremental unit NO_X control cost compared against the SNCR with basic SOFA alternative (Point D) ($7,173/ton and

$7,058/ton, vs $3,894/ton and $4,060/ton respectively). Coal Reburn with boosted SOFA (Points G) was even more incrementally costly versus SNCR with boosted SOFA (Points E) ($27,560/ton and $27,122/ton, vs $($7,173/ton and $7,058/ton respectively).

In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.4-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $441/ton to $6,504/ton. Table 2.4-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $208/ton to $4,293/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

Various combinations of NO_X control technologies evaluated for control and cost-effectiveness are considered to be technically feasible for LOS Unit 1, but have much higher installation and operating costs compared with basic SOFA alone. This confirms the analysis performed by the EPA for establishing the presumptive limits for BART NO_X emissions from pulverized coal-fired EGUs: that the application of current combustion control technology, [primarily low-NOx burners and overfire air] is generally, but not always, more cost-effective than post-combustion controls. Based on the cost impact analysis and the premise that LOS Unit 1's historic and PTE annual average baseline emissions already meet the presumptive BART NO_X level of 0.29 lb/mmBtu, only the least-cost alternative of basic separated overfire air was considered for further impact and visibility impairment evaluations for LOS Unit 1 NO_X emissions control.

The other elements of the fourth step of a BART analysis after the cost impact analysis include evaluating the following impacts:

- Energy impacts.
- Non-air quality environmental impacts.
- Remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the levelized annual cost impact estimates. The other impacts for the single LOS Unit 1 NO_X emissions control alternative chosen to be evaluated further are discussed in Section 2.4.2 and Section 2.4.3. Visibility impairment impacts evaluated for selected LOS Unit 1 NO_X emissions controls are summarized in Section 2.4.4.

(The following article is an addition to the August 2006 BEPC BART Determination Study report.)

[The same basic kinds of energy impacts for NO_X emissions controls described in the August 2006 BEPC LOS BART Report were evaluated for the SOFA with SNCR alternative for LOS Unit 1.]

2.4.2.1 ENERGY IMPACTS OF SOFA with SNCR NO_X CONTROL ALTERNATIVE – LOS UNIT 1

Another feasible NO_X control alternative was reviewed for significant or unusual energy penalties or benefits associated with its use on LOS Unit 1.

Basic SOFA with SNCR operation on LOS Unit 1 may require slightly higher forced draft fan power consumption resulting from higher fan discharge pressure, with combustion air damper actuators' electrical power demand expected to be an insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 1. Higher windbox pressure and ductwork pressure drop impacts of the SOFA system on the forced draft fans' and induced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans).

The SNCR portion of this layered alternative involves a chemical reagent injected for NO_X control, assumed to be aqueous urea. The injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances. Heat is required for urea reagent storage, assumed to be applied to outside concentrated aqueous urea storage tank(s). For the basic SOFA with SNCR alternative, the source of heat is assumed to be auxiliary electrical power. Together, the addition of SNCR to LOS Unit 1 is estimated to consume 35.8 kW, which was calculated following EPA OAQPS convention[2]. Based on operation for the entire year with the assumed 99% availability factor, this would consume approximately 310,000 kW-hr/yr of additional auxiliary electrical power.

Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water; this follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. Reagent dilution water for those SNCR alternatives that involve a chemical reagent injected for NOx control were assumed to be four times the amount of delivered aqueous urea solution consumption (assumes urea is a 50% solution as delivered and is

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[2]. See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-34.

injected as a 10% solution); this also follows EPA OAQPS convention[3]. This was estimated to be approximately 6.2 million Btu per hour, or 53,645 mmBtu/yr.

Likewise, operation of a basic SOFA with SNCR alternative may cause a small increase in levels of unburned carbon in the flyash emitted from the LOS Unit 1 boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

As discussed above, SNCR operation will cause a slight decrease (approximately 0.2%) on the LOS Unit 1 plant unit heat rate (higher Btu/kW-hr), primarily to higher flue gas moisture with corresponding sensible and latent heat losses which would require a slightly higher gross heat input to evaporate the extra dilution water input. This ignores the slight increase in induced draft fan horsepower and auxiliary electrical power consumption to handle the extra coal combustion products, urea and dilution water flows that will result in increased flue gas mass flow during SNCR operation.

LOS Unit 1 boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures is not expected to change significantly, as a slight increase during air-staged burner operation with SOFA may be offset by a slight depression from the injection of the urea dilution water. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This impact on the LOS Unit 1 boiler's thermal conversion efficiency and steam cycle impacts from small steam temperature changes was not quantified, but is not expected to be significant.

SOFA and SNCR are not expected to significantly reduce LOS Unit 1 reliability and availability to generate electrical power. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion of the steel waterwall tubes by sulfur compounds in the furnace gases being created above the burners and below the SOFA injection ports. Due to the moderate sulfur content in the lignite and modest amount of air-staging during firing of the existing low-NO_X burners expected during SOFA operation, this potential change in corrosion rate of the boiler tubes is expected to be minor. This degradation is expected to occur

[3] See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-35.

over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes and superheater/reheater tube banks to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube and superheater/reheater tube failures and changeouts is difficult to estimate, and has not been quantified. SNCR with SOFA operation of LOS Unit 1 may also cause a slight increase in fireside deposit accumulation, especially in the primary and possibly secondary superheater and reheater tube banks. This is expected to be minor, and removed during periodic scheduled outages of LOS Unit 1.

Table 2.4-11 summarizes the gross demand and usage of auxiliary electrical power estimated for the two NO_X control alternatives evaluated for impacts on LOS Unit 1. This assumes annual operation for 8,760 hours at a heat input rate of 2,622 mmBtu/hr at the future PTE case conditions.

TABLE 2.4-11 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 1

Alt. No.	NO_X Control Technique	NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage (future PTE case)		
		Aux. Power Demand (1) (kW)	Generation Reduction from Aux. Power Demand(2) (kW-hrs/yr)	Generation Reduction from Reduced Unit Availability(3) (kW-hrs/yr)
D	SNCR with basic SOFA	36.8	318,749	18,893
A	Separated OFA	1	8,760	0

(1) – The NO_X control equipment gross auxiliary electrical power demand is estimated.
(2) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(3) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

(The following article is an addition to the August 2006 BEPC BART Determination Study report)

[The same basic kinds of non-air environmental impacts for NO_X emissions controls described in the August 2006 BEPC LOS BART Report were evaluated for the SOFA with SNCR alternative for LOS Unit 1.]

2.4.3.2 NON AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF SOFA with SNCR – LOS UNIT 1

Operation of an SNCR-related system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR depends on the amount of reagent utilization and location of the injection points. Higher SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

Ammonia slip is typically controlled to less than 10 ppmvd, especially since the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates. Boiler combustion air heaters, whether tubular or rotary regenerative types, can become fouled with such sulfate compounds. An extension of scheduled unit outages or forced outages (unlikely) could occur as a result of these sulfate deposit accumulations and the time spent to remove them. This could reduce unit operating time (annual availability), but for LOS Unit 1 is expected to be very small, estimated to be 1% of the annual operating time possible.

Some of the unreacted ammonia from SNCR operation will be collected with the flyash in the electrostatic precipitator. This is not expected to pose any significant hazards in the subsequent disposal of the flyash in the nearby permitted landfill currently used by BEPC for this coal combustion byproduct material.

Storage of urea or ammonia reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Regulation of storage and containment of such reagents as hazardous substances will be under the requirements of various federal Acts, which are not part of this BART impact analysis.

The amount of unburned carbon in the flyash produced by the boiler, collected for disposal or potentially emitted to the atmosphere may increase by small increments due to operation of LOS Unit 1 using separated overfire air for NO_X emissions control. The potential changes in the annual amounts of flyash disposal rates are expected to be inconsequential, and have not been quantified. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

The operation of a system using a basic form of separated overfire air for NO_X emissions control may increase carbon monoxide concentrations in the stack flue gas emitted from the LOS Unit 1 boiler. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

The operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs). The chemical form of the reagent will affect the amount of carbon dioxide emitted, since urea contains CO which is readily converted to CO_2 in the boiler-furnace and convection sections by combining with available free oxygen. One mole of carbon dioxide (CO_2) will be created and emitted for every mole of urea injected for reaction with NO_X. This is a relatively small increase in the total amount of CO_2 produced as part of the combustion of carbon-based fossil fuel in the form of lignite. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reductions from the use of SNCR-related alternatives. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

There were no other adverse or significant changes in non-air quality environmental impacts identified for LOS Unit 1 as a result of using separated overfire air with SNCR for NO_X emissions control. Predicted visibility impairment improvement impacts from the reduction in nitrogen oxides emissions predicted to result from operation of LOS Unit 1 with SOFA and SNCR are discussed in the next section.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study report)

2.4.4 VISIBILITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS –UNIT 1

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source.

For this BART analysis, there were two baseline NO_X emission rates modeled for LOS Unit 1 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the presumptive BART NO_X emission rate. The historic pre-control emission baseline was the 24-hour average actual NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH BART protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period.

The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 1 under the conditions stated above was 813 lb/hr. Visibility impact modeling was performed using the CALPUFF model with the difference between the impacts from historic pre-control baseline and post-control average hourly NO_X emission rates representing the visibility impairment impact reduction. One CALPUFF model run was performed with the LOS Unit 1's basic SOFA NO_X emission rate and another run was subsequently conducted with LOS Unit 1's SOFA with SNCR NO_X emission rate, constant PM emissions, and BART level of SO_2 control assuming the Potential-To-Emit (PTE) boiler design rating for heat input (2,622 mmBtu/hr). The unit NO_X emission rate of 0.168 lb/mmBtu multiplied by the boiler PTE heat input rating of 2,622 mmBtu/hr yields 441 lb/hr for LOS Unit 1 under the future PTE case. This compares to the visibility model using an average post-control hourly future PTE LOS Unit 1 NO_X emission rate of 0.23 lb/mmBtu with the PTE boiler heat input rating to yield 603 lb/hr for operation with basic SOFA.

In keeping with the NDDH BART visibility impairment impact modeling protocol, the BART NO_X post-control future PTE presumptive emission rate (760 lb/hr), basic SOFA, and SOFA with SNCR alternatives all have a different boiler heat input basis than the LOS Unit 1 historic highest 24-hour pre-control NO_X emission baseline (813 lb/hr). The post-control conditions for LOS Unit 1 all assume operation at the boiler PTE heat input capacity rating (future PTE case) of 2,622 mmBtu/hr.

The results of the historic LOS Unit 1 pre-control baseline, presumptive BART NO_X PTE baseline, and future post-control PTE NO_X emission rates for basic SOFA alternatives with and without SNCR-enhancement, modeled with the PTE 90% sulfur emission control rate for LOS Unit 1, are shown in Table 2.4-12. The results of the visibility impairment modeling at the pre-control (protocol) baseline emission rate for LOS Unit 1 showed that Lostwood National Wildlife Refuge exceeded 0.5 deciView for the highest predicted visibility impairment impact (90^{th} percentile, averaged for 2000-2002). Average predicted visibility impairment impacts decreased significantly for the presumptive BART NO_X PTE baseline emission rate, and improved slightly with post-control SOFA with and without SNCR-enhanced PTE NO_X emission rates, modeled with the 90% PTE sulfur emission control rates for LOS Unit 1. The comparison of the incremental average visibility impairment impacts that are predicted for the three PTE sulfur emission control rates for LOS Unit 1 is shown elsewhere in Section 3.4.4.

TABLE 2.4-12 – Average Visibility Impairment Impacts from NO_X Controls – LOS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[(1)]			
	Historic Pre-Control (Protocol) Baseline[(2)] (dV)	Presumptive BART NO_X PTE Baseline[(3)] (dV)	PTE Emissions with basic SOFA NO_X Control[(4)] (dV)	PTE Emissions with basic SOFA+SNCR NO_X Control[(5)] (dV)
TRNP-South Unit	0.423	0.107	0.099	0.091
TRNP-North Unit	0.450	0.118	0.111	0.102
TRNP-Elkhorn Ranch	0.287	0.080	0.073	0.066
Lostwood NWR	0.639	0.171	0.153	0.132

(1) - Average predicted visibility impairment impacts (90^{th} percentile) relative to background for years 2000-2002. Pre-control baseline impacts are from highest historic 24-hour NO_X, SO_2, and PM emission rates (NDDH BART protocol). Presumptive BART NO_X emission limit, basic SOFA NO_X and basic SOFA + SNCR NO_X emission rate impacts are from PTE heat input conditions. A summary of the initial modeling scenarios was provided in the August 2006 BART Determination Study final draft report Table 1.4-1 and the modeling results were presented in Appendix D. SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case.

(2) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr.

(3) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr).
(4) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA control alternative's post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr).
(5) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr).

The results of the visibility impairment modeling at the presumptive BART NO_X PTE emission rate (760 lb/hr) with the PTE 90% sulfur emission control rate for LOS Unit 1 again showed that Lostwood National Wildlife Refuge had the highest predicted improvement in visibility impairment compared to the pre-control (protocol) baseline levels. Average predicted visibility impairment reduction also increased with basic SOFA with and without SNCR-enhanced post-control NO_X PTE emission rates from LOS Unit 1 for Lostwood NWR (approximately 0.5 deciView reduction). This is shown in Table 2.4-13.

TABLE 2.4-13 – Average Visibility Impairment Impact Reductions from NO_X Controls – LOS Unit 1 (Post-Control PTE Emissions vs Historic Baseline)

Federal Class 1 Area	Visibility Impairment Reductions[1]		
	Presumptive BART NO_X PTE Baseline[2] (dV)	**PTE Emissions, basic SOFA NO_X Control[3] (dV)**	**PTE Emissions with basic SOFA+SNCR NO_X Control[4] (dV)**
TRNP-South Unit	0.316	0.323	0.332
TRNP-North Unit	0.332	0.339	0.348
TRNP-Elkhorn Ranch	0.207	0.214	0.220
Lostwood NWR	0.467	0.486	0.507

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to historic pre-control emission rates (NDDH BART protocol) for years 2000-2002. Presumptive BART NO_X and SOFA NO_X impacts are from PTE heat input emission rates. SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case scenario.
(2) - Difference of average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr minus average of year 2000-2002 (annual) predicted visibility impairments modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr).
(3) - Difference of average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr minus average of year 2000-2002 (annual)

predicted visibility impairments modeled at basic SOFA control alternative's post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr).

(4) - Difference of average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr).

This analysis includes calculation of the average incremental reduction of the predicted visibility impairment impact for basic SOFA with and without SNCR-enhanced alternatives' PTE emission levels evaluated for the future PTE case operation of LOS Unit 1 compared to presumptive BART NO_X control effectiveness. The results are shown in Table 2.4-14.

TABLE 2.4-14 –Visibility Impairment Reduction from NO_X Controls (vs Presumptive BART NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction PTE Emissions, basic SOFA NO_X Control(1) (dV)	Incremental Visibility Impairment Reduction PTE Emissions with basic SOFA+SNCR NO_X Control(2) (dV)	Additional Incremental Visibility Impairment Reduction PTE Emissions with basic SOFA+SNCR NO_X Control(3) (dV)
TRNP-South Unit	0.00733	0.0157	0.00833
TRNP-North Unit	0.00733	0.0160	0.00867
TRNP-Elkhorn Ranch	0.00733	0.0137	0.00633
Lostwood NWR	0.0183	0.0393	0.0210

(1) - Incremental average predicted visibility impairment impact reductions (90^{th} percentile) relative to presumptive BART post-control PTE NO_X mass emission hourly rate for years 2000-2002. SOFA NO_X post-control impacts are from PTE heat input emission rates, with SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

(2) - Incremental average predicted visibility impairment impact reductions (90^{th} percentile) relative to presumptive BART post-control PTE NO_X mass emission hourly rate for years 2000-2002. SOFA + SNCR post-control NO_X impacts are from PTE heat input emission rates, with SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

(3) - Additional incremental average predicted visibility impairment impact reductions (90^{th} percentile) relative to basic SOFA post-control PTE NO_X mass emission hourly rate for years 2000-2002. SOFA + SNCR post-control NO_X impacts are from PTE heat input emission rates, with SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

Table 2.4-14 shows that incremental visibility impairment improvements predicted to result from applying the basic SOFA with and without SNCR-enhanced alternatives to the presumptive BART NO_X PTE emission rate for LOS Unit 1 are very small. The amount of visibility impairment predicted for natural background conditions is much greater in magnitude than the amount predicted from LOS Unit 1's post-control NO_X PTE emissions contribution alone. The data also shows that reductions in predicted visibility impairment impacts that result from a combination of presumptive

BART NO_X PTE emissions and SO_2 PTE emissions at the 90 percent (or better) control levels compared to the pre-control (protocol) emission conditions are much greater in significance than the incremental improvements of predicted visibility impairment from additional reductions in NO_X emissions.

This analysis also includes a determination of the incremental cost-effectiveness of reducing predicted visibility impairment impact for the SOFA with and without SNCR-enhanced alternatives being evaluated for LOS Unit 1. The estimated LTAC for reducing NO_X emissions from LOS Unit 1 expected to result from separated overfire air (SOFA) for the future PTE case are shown in Table 2.4-6. The comparison in Table 2.4-15 shows that the ratio of the estimated additional annualized costs of installing and operating SOFA with and without SNCR-enhanced alternatives for the future PTE conditions to the average predicted visibility impairment improvement relative to the presumptive BART NO_X PTE baseline emission rate for the future PTE case applied to LOS Unit 1 would result in millions of dollars per deciView of visibility impairment improvement.

TABLE 2.4-15 – Cost Effectiveness of Visibility Impairment Reduction from NO_X Controls (vs Presumptive NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, basic SOFA NO_X Control(1) ($/dV-yr)	Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, basic SOFA + SNCR NO_X Control(2) ($/dV-yr)	Additional Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, basic SOFA + SNCR vs SOFA NO_X Control(3) ($/dV-yr)
TRNP-South Unit	19,640,000	197,800,000	354,600,000
TRNP-North Unit	19,640,000	193,700,000	341,000,000
TRNP-Elkhorn Ranch	19,640,000	226,800,000	466,600,000
Lostwood NWR	7,860,000	78,800,000	140,700,000

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002 with SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. Basic SOFA NO_X impacts are from PTE heat input emission rates. Control costs are levelized annual values for installed capital + O&M for basic SOFA NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

(2) - Average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002 with SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. Basic SOFA+SNCR NO_X impacts are from PTE heat input emission rates. Control costs are levelized annual values for

installed capital + O&M for basic SOFA+ SNCR NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

(3) - Average predicted incremental visibility impairment impact reductions (90th percentile) relative to basic SOFA NO_X PTE emission rates for years 2000-2002 with SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. Basic SOFA and basic SOFA with SNCR NO_X impacts are from PTE heat input emission rates. Incremental control costs are levelized annual values for installed capital + O&M for basic SOFA with SNCR control vs basic SOFA NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

The number of days predicted to have visibility impairment due to LOS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) hourly NO_X, SO_2, and PM emission rates described previously in this Section. The results are summarized and presented in the Screening Analysis Table of Appendix D. Similarly, the same information for the post-control SO_2 and PM alternatives for LOS Unit 1 with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 3.4-15. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between presumptive BART NO_X emission rates versus basic SOFA-controlled LOS Unit 1 NO_X emission rates with post-control SO_2 and PM alternatives are summarized and shown in Table 2.4-16. The reductions in the average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between presumptive BART NO_X emission rates versus basic SOFA with SNCR-controlled NO_X emission rates with post-control SO_2 and PM alternatives for LOS Unit 1 are also summarized and shown in Table 2.4-16.

The magnitude of predicted visibility impairment impacts and number of days predicted to have visibility impairment impact greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2000 for Lostwood NWR. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for both the pre-control and post-control model results is included in Section 3.4. The post-control SO_2 and PM alternatives with SOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same post-control SO_2 and PM conditions with presumptive BART NO_X PTE emission rates. The number of days are presented in Appendix D. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SOFA-controlled PTE emission rates compared to presumptive BART NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.4-9, 2.4-10, and 2.4-11.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.4.5 SUMMARY OF IMPACTS OF LOS NO_X CONTROLS – UNIT 1

Table 2.4-17 summarizes the various quantifiable impacts discussed in Sections 2.4.1 through 2.4.4 for the single BART NO_X alternative evaluated for LOS Unit 1.

Table 2.4-16 – Visibility Impairment Reductions – Basic SOFA and Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

Class 1 Area	NO_X Control Technique[(1)]	Visibility Impairment Reduction (ΔdV)	ΔDays[(2)] Exceeding 0.5 dV in 2000	ΔDays[(2)] Exceeding 0.5 dV in 2001	ΔDays[(2)] Exceeding 0.5 dV in 2002	ΔDays[(2)] Exceeding 1.0 dV in 2000	ΔDays[(2)] Exceeding 1.0 dV in 2001	ΔDays[(2)] Exceeding 1.0 dV in 2002	ΔConsecutive Days[(2)] Exceeding 0.5 dV 2000	ΔConsecutive Days[(2)] Exceeding 0.5 dV 2001	ΔConsecutive Days[(2)] Exceeding 0.5 dV 2002
TRNP South	Basic SOFA	0.00733[(3)]	1	0	0	0	0	0	0	0	0
TRNP North	Basic SOFA	0.00733[(3)]	2	3	2	0	0	0	0	1	0
TRNP Elkhorn	Basic SOFA	0.00733[(3)]	1	0	1	1	0	1	0	0	0
Lostwood NWR	Basic SOFA	0.0183[(3)]	0	0	2	0	2	0	0	0	0
TRNP South	Basic SOFA+SNCR	0.0157[(4)]	2	2	3	1	0	0	0	1	0
TRNP North	Basic SOFA+SNCR	0.0160[(4)]	3	3	4	1	0	2	0	1	0
TRNP Elkhorn	Basic SOFA+SNCR	0.0137[(4)]	1	0	1	1	0	1	0	0	0
Lostwood NWR	Basic SOFA+SNCR	0.0393[(4)]	1	4	4	0	3	2	0	0	0

1 - SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
2 - Difference in number of days is 100th percentile level for predicted visibility impacts in Table 3.4-15.
3 - Average predicted visibility impairment reductions (90th percentile) from all PTE emissions for SO_2 and PM post-control alternatives with basic SOFA NO_X control at 0.23 lb/mmBtu relative to presumptive NO_X emission level of 0.29 lb/mmBtu with PTE heat input emission rates (future PTE case), years 2000-2002.
4 - Average predicted visibility impairment reductions (90th percentile) from all PTE emissions for SO_2 and PM post-control alternatives with basic SOFA + SNCR NO_X control at 0.168 lb/mmBtu relative to presumptive NO_X emission level of 0.29 lb/mmBtu with PTE heat input emission rates (future PTE case), years 2000-2002.

Figure 2.4-9 – Days of Visibility Impairment Reductions – 0.5 dV
Basic SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

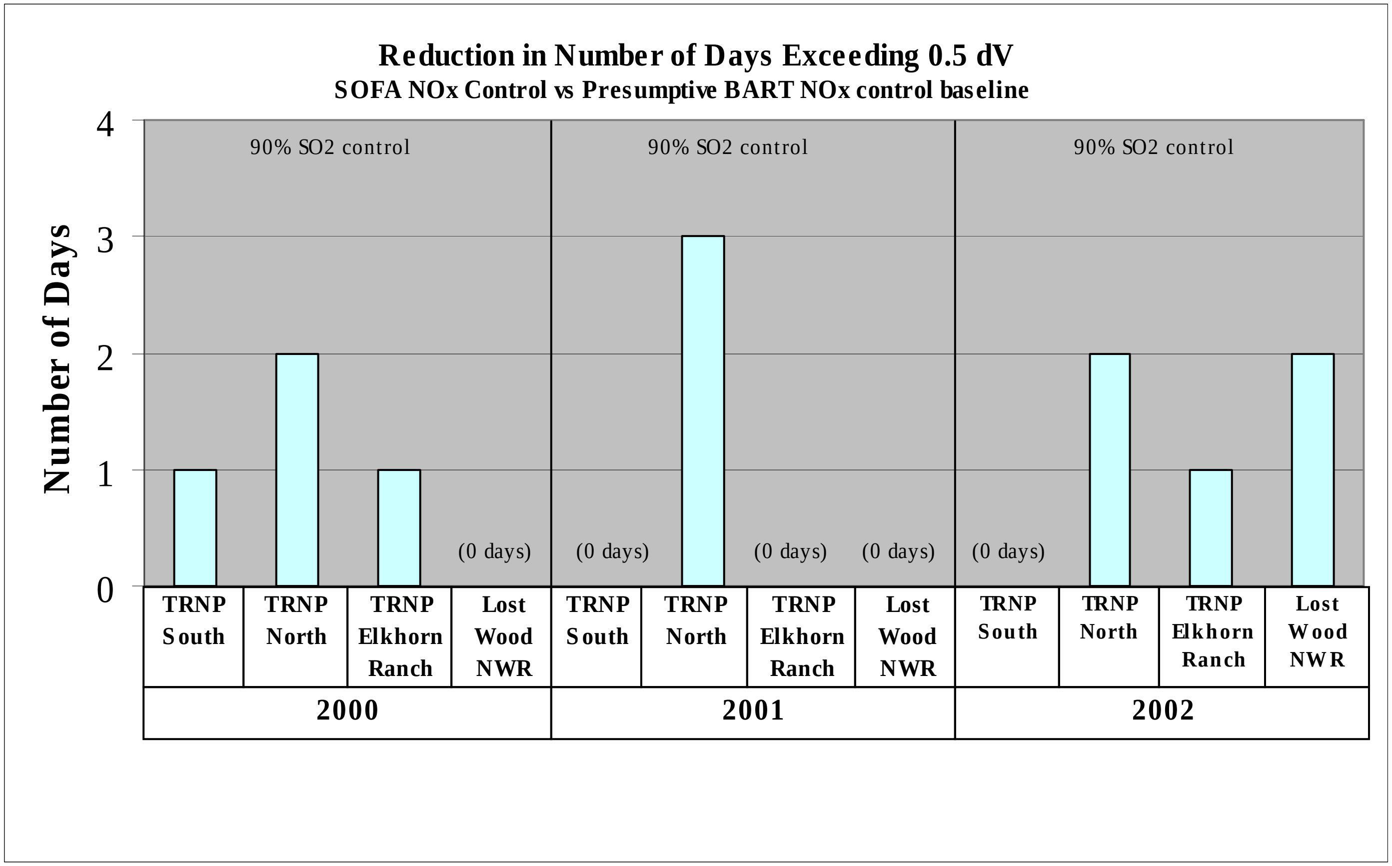


Figure 2.4-10 – Days of Visibility Impairment Reductions – 1.0 dV
Basic SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

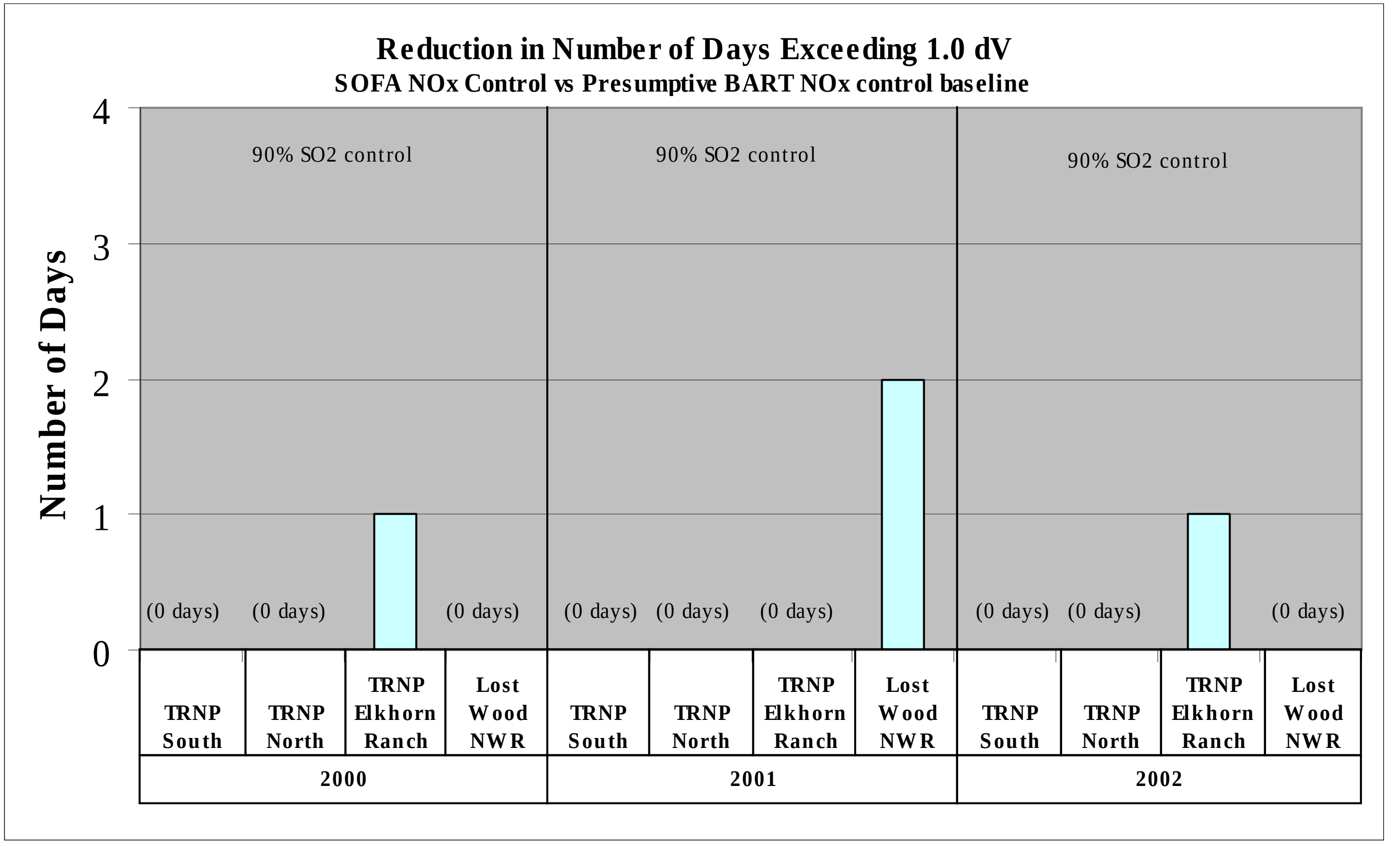


Figure 2.4-11 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV Basic SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

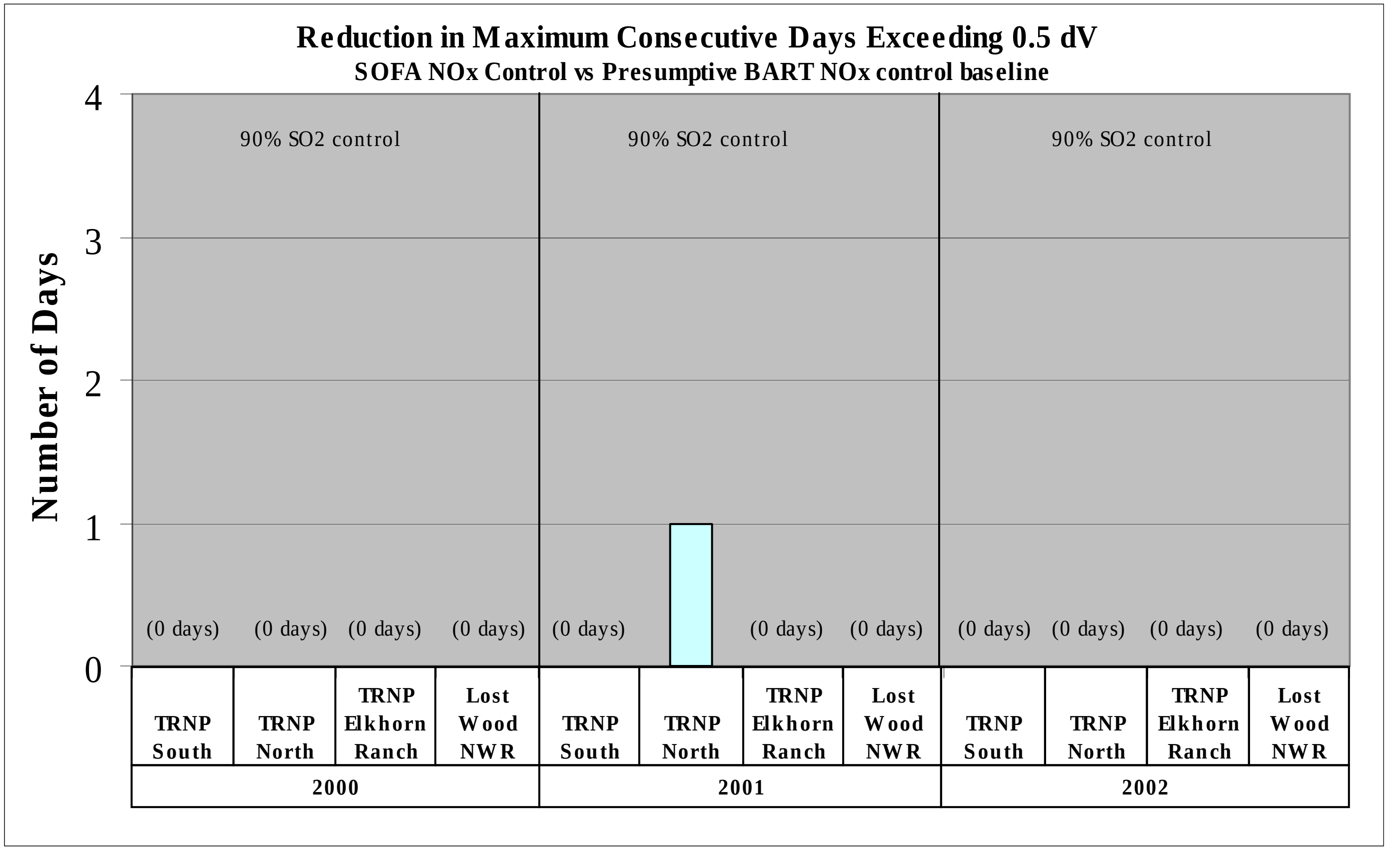


Figure 2.4-12 – Days of Visibility Impairment Reductions – 0.5 dV
Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

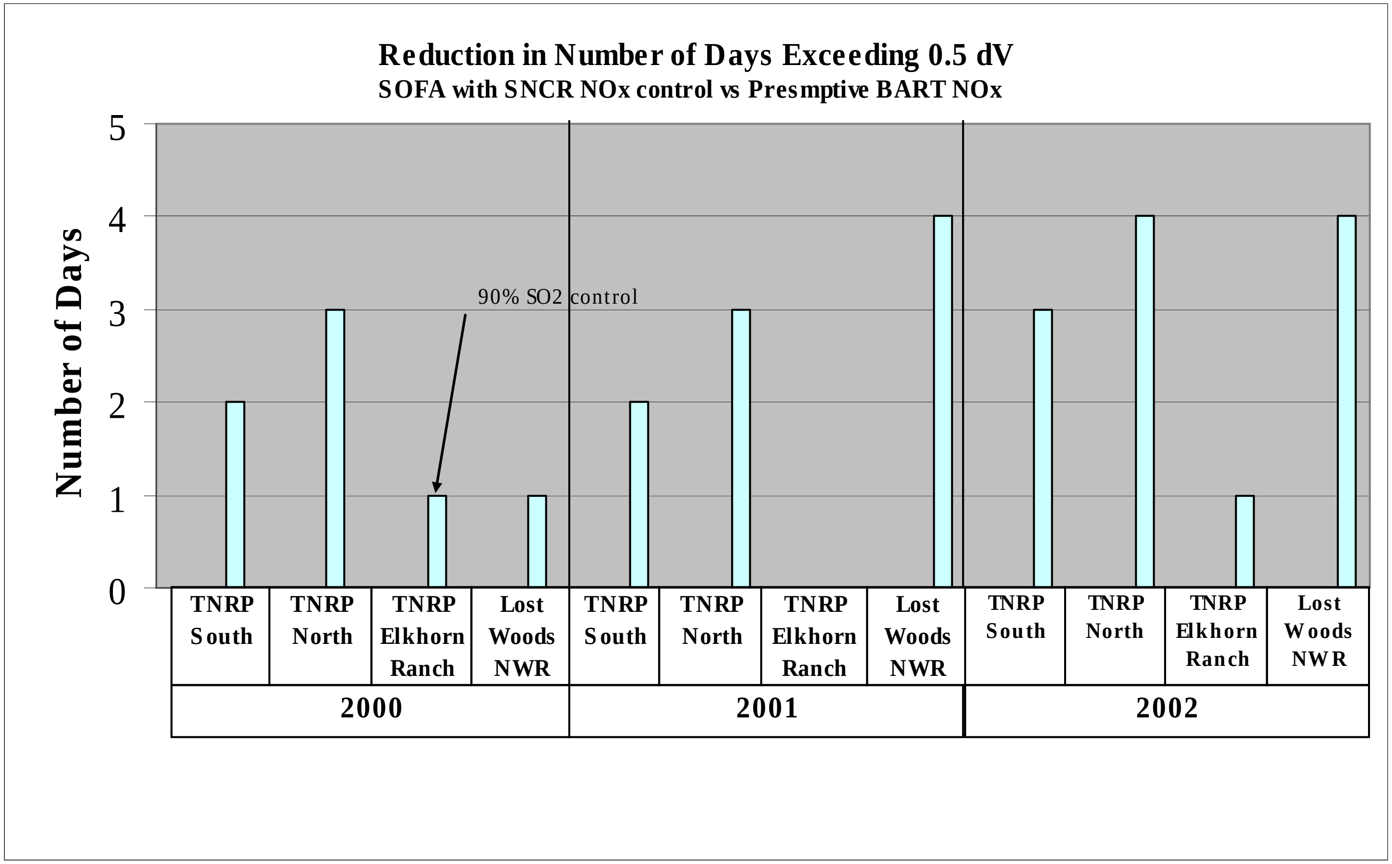


Figure 2.4-13 – Days of Visibility Impairment Reductions – 1.0 dV
Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

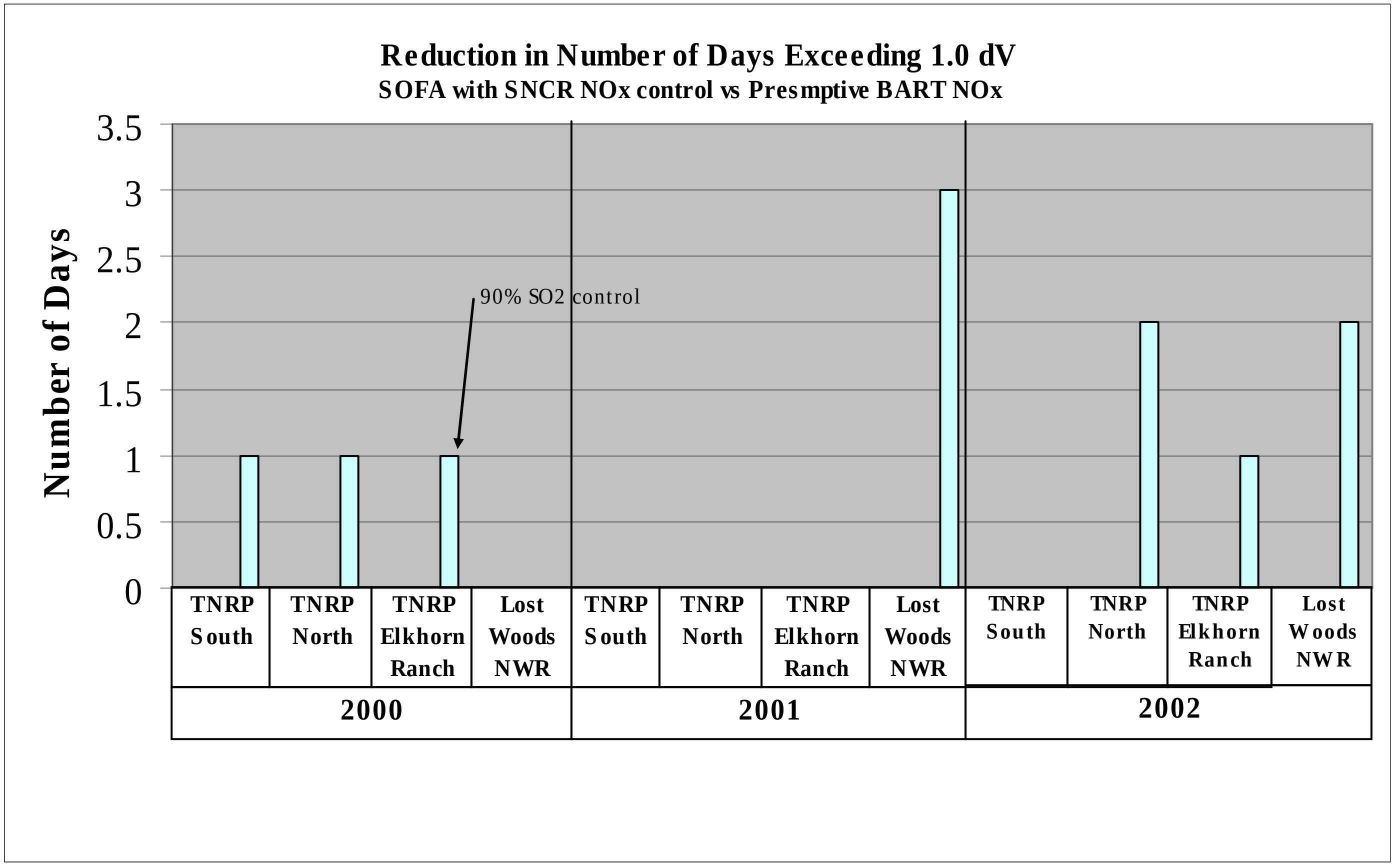


Figure 2.4-14 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

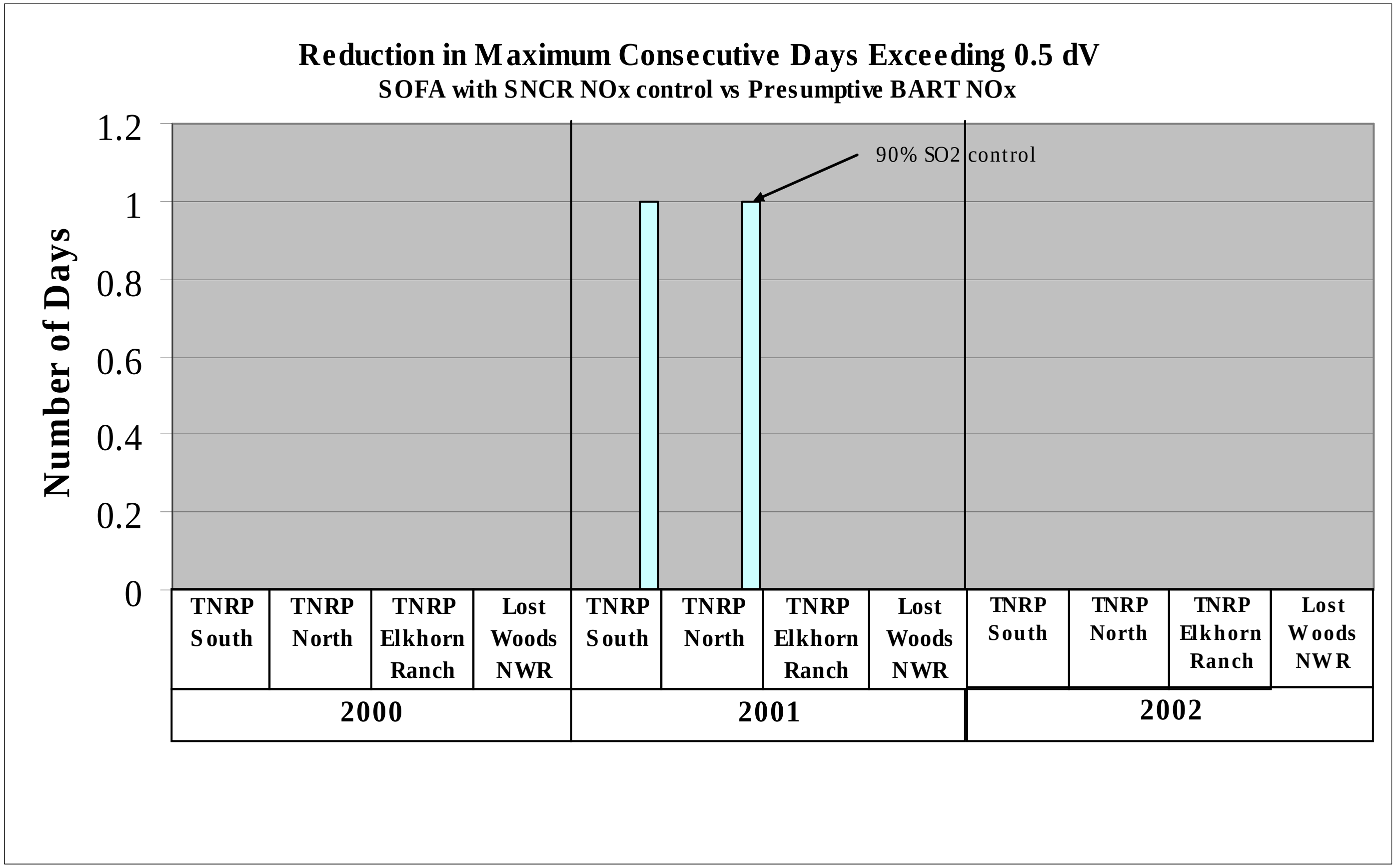


Figure 2.4-15 – Days of Visibility Impairment Reductions – 0.5 dV
Basic SOFA + SNCR Control vs SOFA NO_X Control with SO_2 and PM Controls
LOS Unit 1

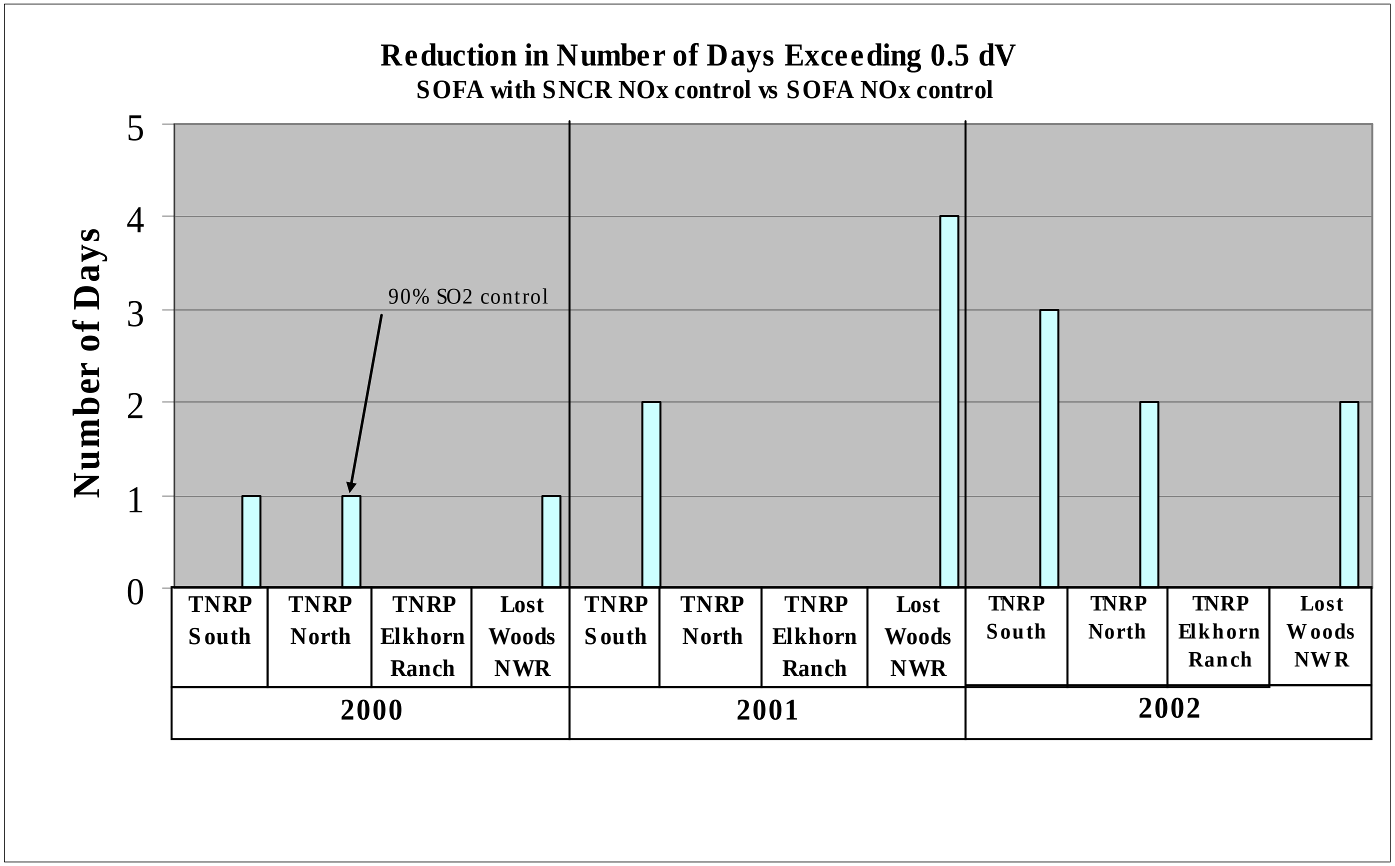


Figure 2.4-16 – Days of Visibility Impairment Reductions – 1.0 dV
Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

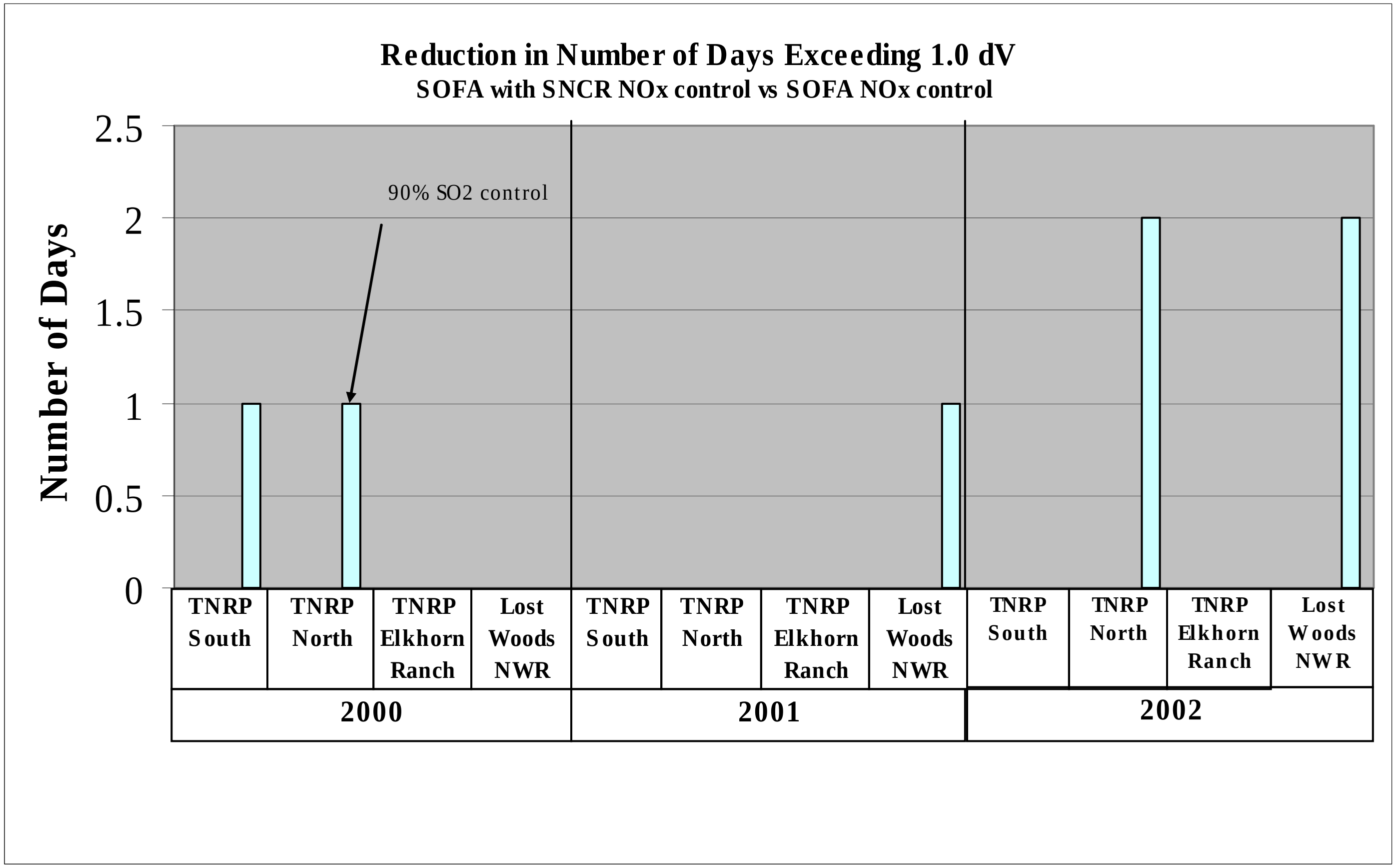


Figure 2.4-17 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

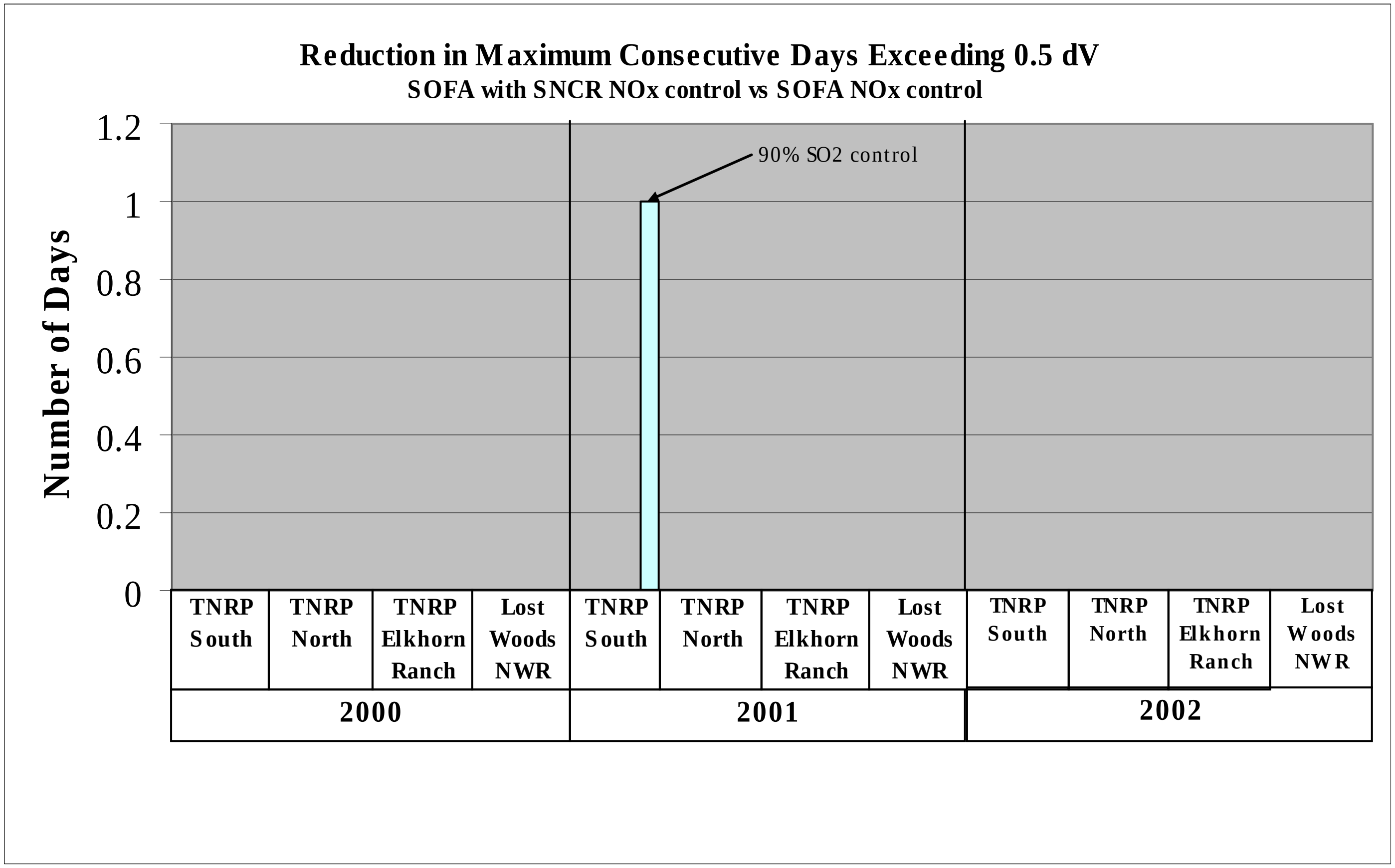


Table 2.4-17 – Impacts Summary for LOS Unit 1 NO_X Controls (vs Presumptive BART NO_X PTE Emissions)

NO_X Control Technique w/ SO_2 Control Level	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost(1) ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1), (2) ($/dV)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental ΔdV			
Basic SOFA w/ 90% SO_2 Control	20.7%	689	$144,000	$208	TRNP-S	0.00733(3)	$19,640,000	1	Flyash unburned carbon increase
					TRNP-N	0.00733(3)	$19,640,000		
					TRNP-Elk	0.00733(3)	$19,640,000		
					LNWR	0.0183(3)	$7,860,000		
Basic SOFA + SNCR w/ 90% SO_2 Control	42.0%	1,417	$3,100,000	$2,187	TRNP-S	0.0157(4)	197,800,000	36.8	Flyash unburned carbon increase, ammonia in flyash
					TRNP-N	0.0160(4)	193,700,000		
					TRNP-Elk	0.0137(4)	226,800,000		
					LNWR	0.0393(4)	78,800,000		
Basic SOFA + SNCR vs basic SOFA, w/ 90% SO_2 Control	26.8(5)	728(5)	$2,955,000 (5)	$4,059	TRNP-S	0.00833(5)	354,600,000(5)	35.8(5)	ammonia in flyash
					TRNP-N	0.00867(5)	341,000,000(5)		
					TRNP-Elk	0.00633(5)	466,600,000(5)		
					LNWR	0.0210(5)	140,700,000(5)		

(1) - All cost figures in 2005 dollars. See Table 2.4-6 for details.
(2) - LTAC for post-control NO_X control alternative divided by Incremental ΔdV.
(3) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 (annual) modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr) minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA control alternative's post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr) with SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case) for both cases. This case assumes 90% SO_2 control over pre-control baseline.
(4) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 (annual) modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr) minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr) with SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case) for both cases. This case assumes 90% SO_2 control over pre-control baseline.

(5) - Average predicted incremental visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 (annual) modeled at SOFA post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr) minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr) with SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case) for both cases. This case assumes 90% SO_2 control over pre-control baseline.

(The following article is a copy of the same section in the August 2006 BEPC BART Determination Study final draft report. It is included here for continuity from the corrected and amended Unit 1 portion of the BEPC BART Determination Study report and the corrected Unit 2 portion that follows)

2.5 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS – LOS UNIT 2

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the control technologies from consideration for Leland Olds Station Unit 2.

2.5.1 COST IMPACTS OF NO_X CONTROLS – LOS UNIT 2

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on LOS Unit 2 boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 2.5-1 through 2.5-8. From Step 3 of the BART analysis, compared with other similarly-effective NO_X controls, conventional gas reburn alternatives would have high expected capital costs for a natural gas supply pipeline and on-going natural gas costs. Thus, otherwise technically feasible gas-consuming alternatives are considered economically unattractive for application at LOS on the Unit 2 boiler.

Although the BART Guidelines prescribes following a “top down” analysis approach for BART determination, the development of a least cost envelope with dominant controls[1] [70 FR 39168] clearly labels points with lower emissions reductions and total annual costs first, i.e. “A”, “B”, etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NO_X control technique alternative has followed this approach.

2.5.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS - LOS UNIT 2

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases involving SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor range and single point unit capital cost factor for the feasible NO_X emission reduction technology evaluated for LOS Unit 2 are presented in Table 2.5-1.

TABLE 2.5-1 – Unit Capital Cost Factors of Feasible NO_X Control Options for LOS Unit 2

Alt. No. (1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) LOS Unit 2
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20 + ?(4)	46(4),(5),(6)
C	SNCR (using urea) w/ ASOFA	20-35(7)	38(5),(6)
B	Coal Reburn (conventional, pulverized) w/ ASOFA	30-60(7)	153(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	23(6)

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2005 dollars.
(4) – No published RRI unit capital cost factor was found in available technical literature. The installed capital costs for RRI are expected to be similar to SNCR. If both RRI and SNCR are installed together, capital cost of the RRI+SNCR portion was assumed to be 1.5x the capital cost of SNCR alone, due to commonality between the two systems sharing certain equipment and systems.
(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix A for details.
(6) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(7) – NESCAUM 2005 Technical Paper, posted at their website for basic SOFA. See Appendix A for details.

(8) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 57.5 $/kW. See Appendix A for details.

Annualized capital cost, which includes the time value of capital monies and its recovery, is determined from the estimated capital cost and the methodology described in Section 1. Table 2.5-2 shows the estimated installed capital cost and annualized capital cost values for the highest-performing form of the various feasible NO_X emission reduction technologies applied to LOS Unit 2. These were developed by multiplying the unit capital cost single point factors for the control option by the nameplate output capacity rating of the respective unit. These are listed in order of control effectiveness, with the highest ranked options at the top.

TABLE 2.5-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Alternatives - LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Installed Capital Cost(2) ($1,000)	Annualized Capital Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20,200	1,760
C	SNCR (using urea) w/ ASOFA	16,800	1,470
B	Coal Reburn (conventional, pulverized) w/ ASOFA	67,400(4)	5,880(4)
A	Advanced Separated Overfire Air (ASOFA)	10,100	883
	Baseline	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on existing nameplate rating of 440,000 kW. Installed capital cost figures in 2005 dollars.
(3) – Annualized capital cost = Installed capital cost x 0.08718 Capital Recovery Factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $25,300,000 for installed capital cost, and $2,200,000/yr annualized capital cost.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 2

The operation and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS), and from engineering judgment applied to that control technology. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR and RRI alternatives; and
- Reagent dilution water consumption and unit cost for SNCR and RRI alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.5-3 and Table 2.5-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 2.5-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,340	13,530
C	SNCR (using urea) w/ ASOFA	6,750	8,060
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,900(4)	7,040(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

Annual operating and maintenance costs of the NO_X control options in Table 2.5-3 and Table 2.5-4 are based on LOS Unit 2 operation with the control option at 5,130 mmBtu/hr heat input and 8,760 hrs/yr operation. The Table 2.5-3 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the highest 24-month NO_X emission summation at 4,478 mmBtu/hr heat input for 8,050 hrs/yr operation of LOS Unit 2. The Table 2.5-4 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the maximum NO_X emissions associated with the future PTE case at 5,130 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 2.

TABLE 2.5-4 – Estimated O&M Costs for NO_X Control Options (Relative to PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 2

Alt. No. [1]	NO_X Control Alternative	Annual O&M Cost[2] ($1,000)	Levelized Annual O&M Cost[3] ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,340	13,530
C	SNCR (using urea) w/ ASOFA	6,750	8,060
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,900[4]	7,040[4]
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

The majority of the annual operating and maintenance costs for the alternatives using chemical reagent injection (urea) for NO_X emissions control are for the delivered reagent and dilution water. Both RRI and SNCR are assumed to dilute the 50% aqueous urea solution as-received to a 10% aqueous urea concentration for direct injection into the targeted furnace areas. Higher than theoretical normalized (molar) stoichiometric ratios (NSRs) for the moles of equivalent reagent injected (urea) per mole of inlet NO_X emission were assumed for SNCR with ASOFA, and for RRI+SNCR with ASOFA due to inefficiencies inherent in their use. These annual costs reflect a significant increase in reagent consumption above the theoretical rates based on expected amounts of reagent utilization.

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART selection process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which in this analysis is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal incurred by implementing that alternative, was calculated. The LTAC for these NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 of this BART evaluation for methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by baseline annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The feasible control alternatives were also compared by calculating the change in LTAC per incremental ton of pollutant removed for the next most stringent alternative (incremental cost effectiveness). This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average LTAC increment compared with the pre-control baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted. These incremental and average control costs relative to the historic pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-5. The incremental and average control costs relative to the PTE pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-6.

TABLE 2.5-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	6,128	15,290	2,500
C	SNCR (using urea) w/ ASOFA	6,762	5,261	9,520	1,810
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	4,908	12,920[5]	2,630[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	1,227	1,060	867
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	12,023	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in an average control cost of $873 per ton of NO_X removed.

TABLE 2.5-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 2

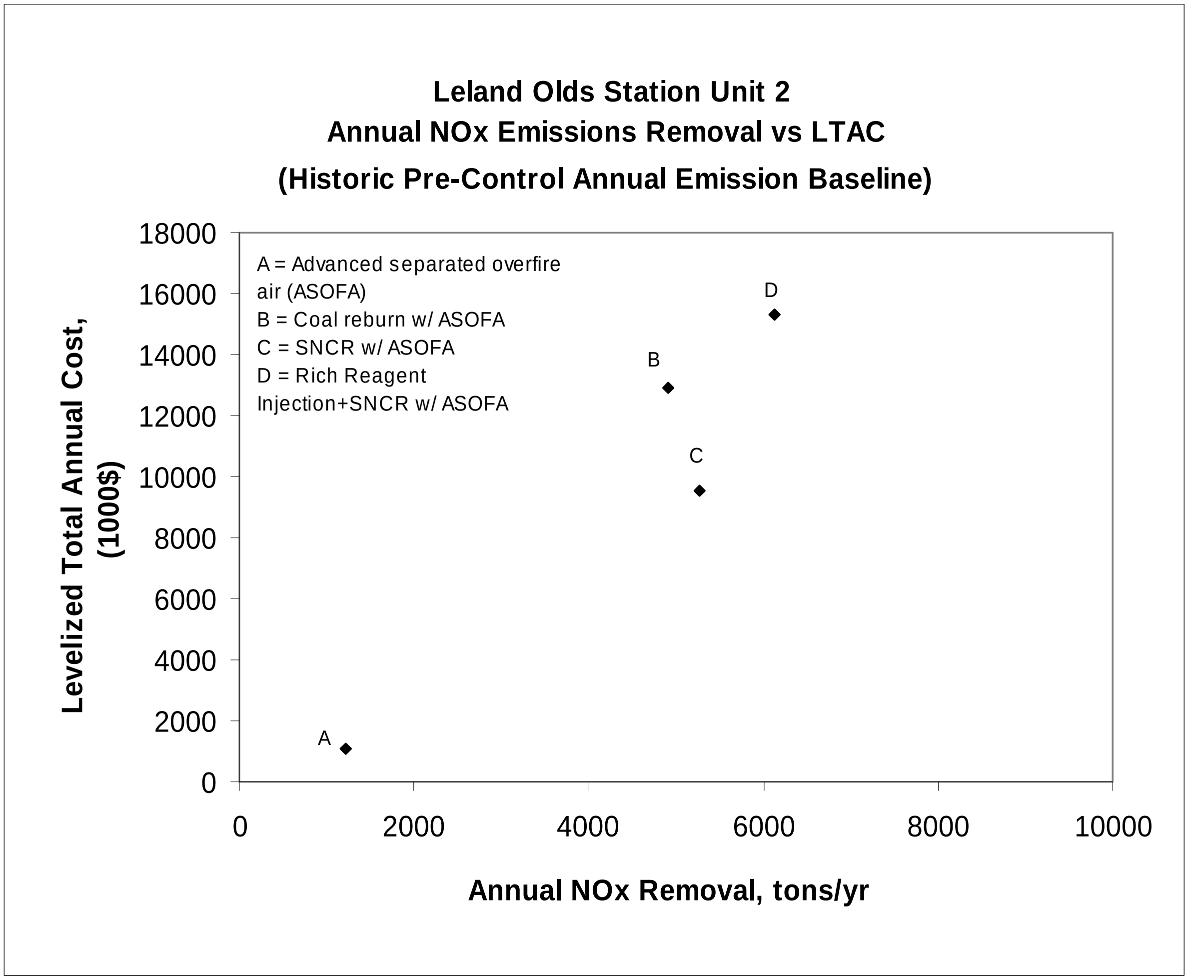
Alt. No. [(1)]	NO_X Control Alternative	Annual NO_X Emissions[(2)] (Tons/yr)	Annual NO_X Emissions Reduction[(2)] (Tons/yr)	Levelized Total Annual Cost[(3),(4)] ($1,000)	Average Control Cost[(4)] ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	9,094	11,340	1,680
C	SNCR (using urea) w/ ASOFA	6,762	8,226	6,750	1,160
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	7,873	5,900[(4)]	1,640[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	4,193	1,060	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	14,989	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-4 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in a average control cost of $544 per ton of NO_X removed.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 2 relative to two different NO_X emission baselines was made and is shown in Figures 2.5-1 and 2.5-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.5-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 2 under the future PTE case.

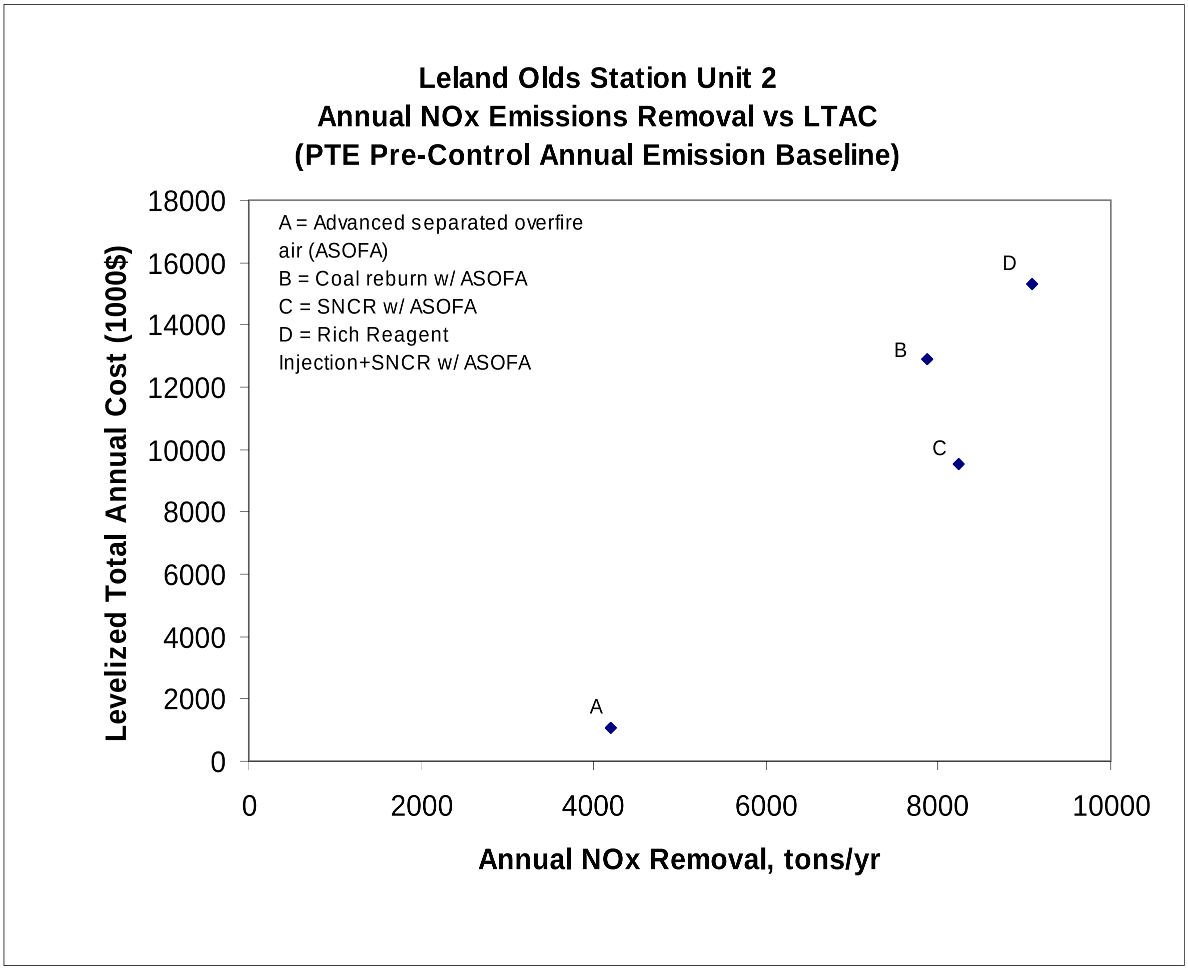
Figure 2.5-1 – NO_X Control Cost Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)[1]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-5.

Figure 2.5-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit 2 under the future PTE case.

Figure 2.5-2 – NO_X Control Cost Effectiveness – LOS Unit 2
(PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-6.

The purpose of Figures 2.5-1 and 2.5-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 2 NO_X control alternatives evaluated for cost-effectiveness, the data point for coal reburn with ASOFA is seen to be more costly for fewer tons of NO_X removed than for SNCR with ASOFA. This appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.5-3 and Figure 2.5-4 contains a repetition of the levelized total annual cost and NO_X control information from Figure 2.5-1 and Figure 2.5-2 with Point B removed, and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point. This modified least-cost controls curve is the Dominant Controls Cost Curve for NO_X emissions alternatives for each of the LOS Unit 2 pre-control baselines evaluated.

TABLE 2.5-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[(2),(3)] ($1,000)	Annual Emission Reduction[(4)] (Tons/yr)	Incremental Levelized Total Annual Cost[(3),(5)] ($1,000)	Incremental Annual Emission Reduction[(4),(5)] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[(3),(6)]
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	15,290	6,128	5,770	867	6,650
C	SNCR (using urea) w/ ASOFA	9,520	5,261	8,460	4,034	2,100
A	Advanced SOFA (ASOFA)	1,060	1,227	1,060	1,227	867
	Baseline, based on annual operation at historic 24-month average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

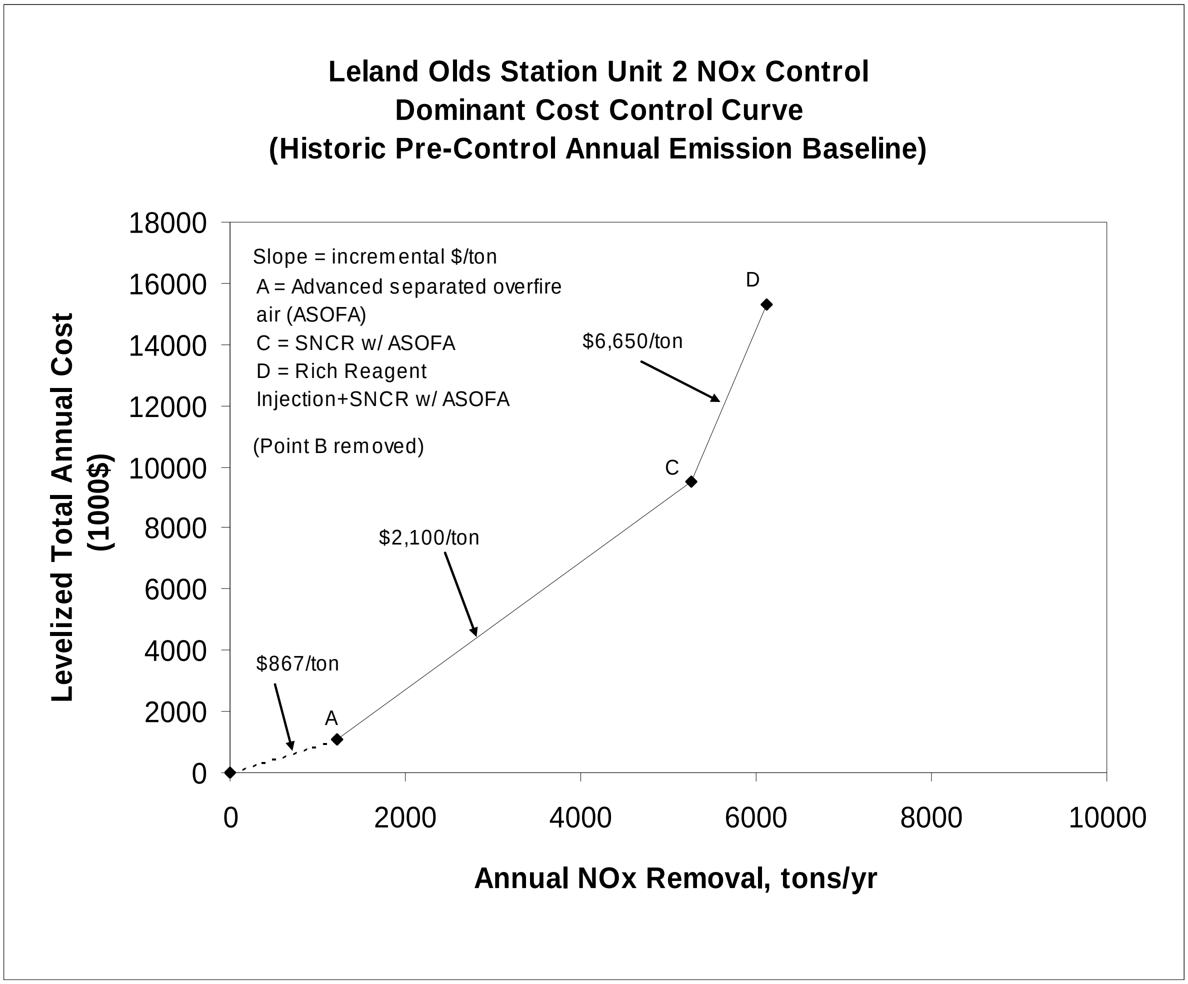
TABLE 2.5-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 2

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[2],[3] ($1,000)	Annual Emission Reduction[4] (Tons/yr)	Incremental Levelized Total Annual Cost[3],[5] ($1,000)	Incremental Annual Emission Reduction[4],[5] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3],[6]
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,340	9,094	5,770	867	6,650
C	SNCR (using urea) w/ ASOFA	6,750	8,226	8,460	4,034	2,100
A	Advanced SOFA (ASOFA)	1,060	4,193	1,060	4,193	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

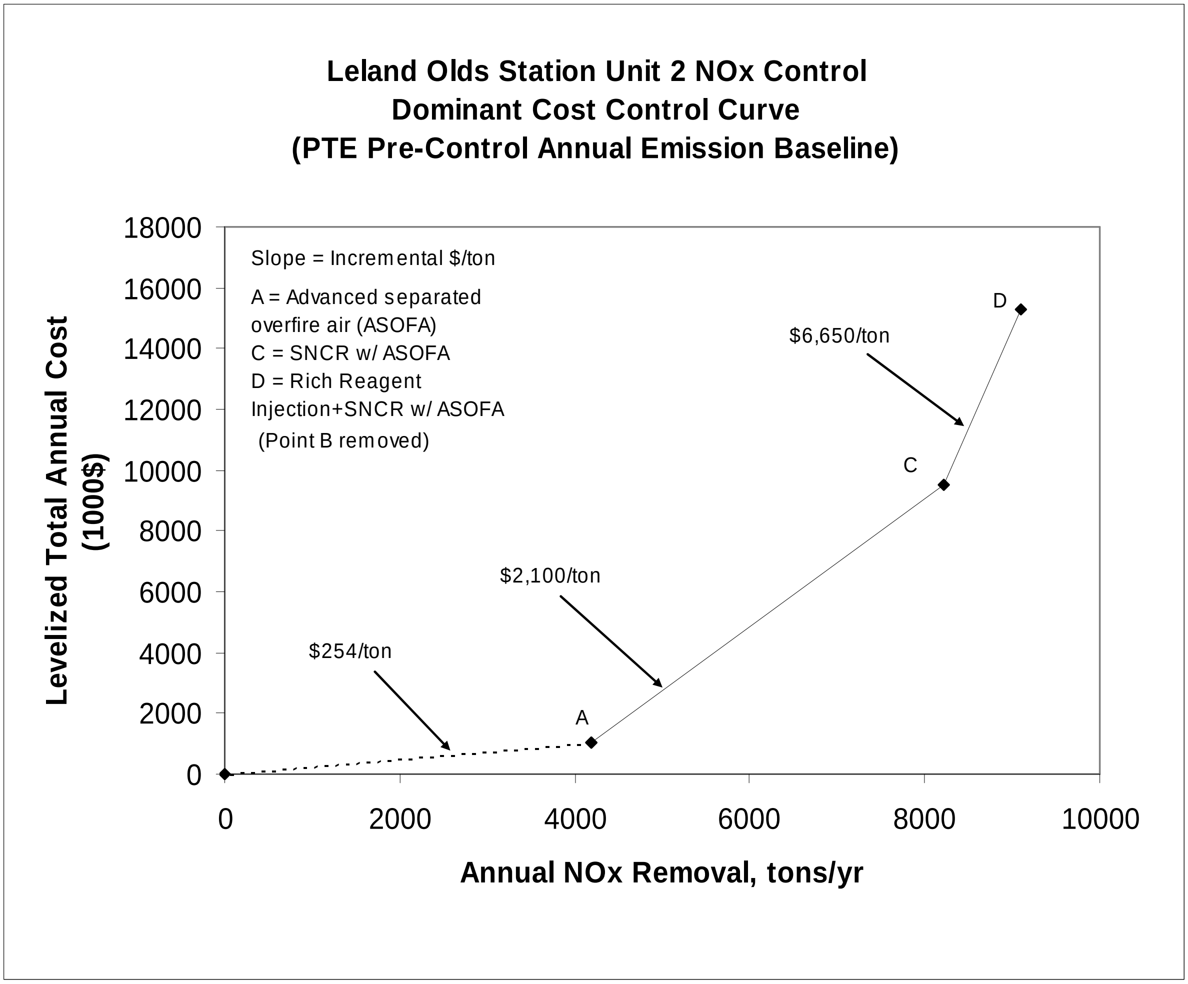
In the comparison displayed in Figure 2.5-3 and Figure 2.5-4, for the data shown in Table 2.5-7 and Table 2.5-8, the RRI+SNCR with Advanced SOFA NO_X control alternative (Point D) had a significantly higher incremental unit NO_X control cost (slope, $6,650/ton) compared against SNCR with ASOFA alternative (Point C) versus SNCR with ASOFA (Point C) compared against the ASOFA alternative (Point A) ($2,100/ton).

Figure 2.5-3 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-7.

Figure 2.5-4 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-8.

In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable, or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.5-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $867/ton to $2,630/ton. Table 2.5-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $254/ton to $1,680/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the Dominant Control Cost Curve) between successively more effective alternatives. The incremental cost analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is Rich Reagent Injection + SNCR with ASOFA (Point D). This control option is considered technically feasible for Leland Olds Station Unit 2 boiler, incurs a significant annual (levelized) incremental cost compared to the next highest feasible NO_X control technique, SNCR with ASOFA (Point C, slope from C to D =6,650 $/ton) compared against the next lowest alternative, ASOFA (Point A, slope from A to C = 2,100 $/ton).

The other elements of the fourth step of a BART analysis following cost of compliance are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimates. The other impacts for the LOS Unit 2 NO_X emissions control alternatives from the Dominant Control Cost Curve are discussed in Section 2.5.2 and Section 2.5.3. Visibility impairment impacts for these LOS Unit 2 NO_X emissions controls are summarized in Section 2.5.4.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.4.6 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 2

Operation of the top NO_X control technologies considered feasible for potential application at the Leland Olds Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various LOS Unit 2 NO_X control alternatives are summarized in Appendix A.

Control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology will result in any significant or unusual energy penalties or benefits. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.2.1 ENERGY IMPACTS OF SOFA ALTERNATIVES – LOS UNIT 1

There should not be a major impact on energy consumption by the operation of the advanced variation of a separated overfire air system. ASOFA was the only NO_X control technology common to all four alternatives evaluated for LOS Unit 2. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Combustion air damper actuators' electrical power demand would be insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 2. For cyclone boilers, providing effective volumes and velocities of separated overfire air at the injection ports should not require higher forced draft fan power consumption resulting from higher fan discharge pressure. Higher lignite drying system vent ductwork pressure drop impacts of the advanced SOFA system on the forced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Operation of a SOFA system may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kw-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate may be more significant.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged cyclone operation with SOFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, once the amount of secondary combustion air that can be withdrawn from the cyclones is established for consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for LOS Unit 2. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.2.2 ENERGY IMPACTS OF SNCR ALTERNATIVES – LOS UNIT 2

The SNCR portion of this layered alternative involves a chemical reagent injected for NO_X control, assumed to be aqueous urea. For SNCR-related NO_X control alternatives (with or without Rich

Reagent Injection), the injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances. Heat is required for urea reagent storage. For the Advanced SOFA + SNCR with and without RRI alternatives, the source of heat is assumed to be auxiliary electrical power, on the order of 150 to 300 kW, which was calculated following EPA OAQPS convention[4]. Based on operation for the entire year with the assumed 99% availability factor, this would consume approximately 310,000 kW-hr/yr of additional auxiliary electrical power.

Advanced SOFA + SNCR with and without RRI alternatives' operation is not expected to require higher forced draft fan power consumption. Combustion air damper actuators' electrical power demands are expected to be an insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 2.

Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water; this follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. Reagent dilution water for those SNCR alternatives that involve a chemical reagent injected for NOx control were assumed to be four times the amount of delivered aqueous urea solution consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this also follows EPA OAQPS convention[5]. This was estimated to be approximately 23.7 million Btu per hour for Advanced SOFA + SNCR, or 204,800 mmBtu/yr and approximately 45.0 million Btu per hour for Advanced SOFA + SNCR with RRI, or 389,500 mmBtu/yr for LOS Unit 2.

Likewise, operation of a Advanced SOFA + SNCR with and without RRI alternatives may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

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[4] See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-34.
[5] See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-35.

As discussed above, SNCR operation will cause a slight decrease (approximately 0.5-0.9%) on the plant unit heat rate (higher Btu/kW-hr), primarily to higher flue gas moisture with corresponding sensible and latent heat losses which would require a slightly higher gross heat input to evaporate the extra dilution water input. This ignores the slight increase in induced draft fan horsepower and auxiliary electrical power consumption to handle the extra coal combustion products, urea and dilution water flows that will result in increased flue gas mass flow during SNCR/RRI operation. The impact of additional flue gas created by operation of an SNCR-related system on induced draft fan power consumption should be insignificant.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures is not expected to change significantly, as a slight increase during air-staged burner operation with SOFA may be offset by a slight depression from the injection of the urea dilution water. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This impact on the LOS Unit 2 boiler's thermal conversion efficiency and steam cycle impacts from small steam temperature changes was not quantified, but is not expected to be significant.

ASOFA and SNCR/RRI are not expected to significantly reduce unit reliability and availability to generate electrical power. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion of the steel waterwall tubes by sulfur compounds in the furnace gases being created above the burners and below the SOFA injection ports. Due to the moderate sulfur content in the lignite and modest amount of air-staging during firing of the existing cyclone burners expected during ASOFA operation, this potential change in corrosion rate of the boiler tubes is expected to be minor. SNCR/RRI may cause a slight increase in fireside deposit accumulation, especially in the primary and possibly secondary superheater and reheater tube banks. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes and superheater/reheater tube banks to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube and superheater/reheater tube failures and changeouts is difficult to estimate, and has not been quantified.

Table 2.5-9 summarizes the gross demand and usage from auxiliary electrical power estimated for the NO_X control alternatives evaluated for LOS Unit 2.

TABLE 2.5-9 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 2

Alt. No.(1)	NO_X Control Technique	NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage		
		Aux. Power Demand (2) (kW)	Generation Reduction from Aux. Power Demand(2),(3) (kW-hrs/yr)	Generation Reduction from Reduced Unit Availability(4) (kW-hrs/yr)
D	RRI + SNCR (using urea) w/ ASOFA	285	2,464,300	38,500,000
C	SNCR (using urea) w/ ASOFA	156	1,349,600	38,500,000
A	Advanced Separated Overfire Air (ASOFA)	1	8,760	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – The NO_X control equipment gross auxiliary electrical power demand is estimated.
(3) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(4) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.4 VISIBLITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source. For this BART analysis, there were two baseline NO_X emission rates assumed for LOS Unit 2 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the Potential-To-Emit (PTE) pre-control annual NO_X emission rate associated with the future PTE case. The historic pre-control emission baseline was the 24-hour average NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period. The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 2 under the conditions stated above was 3,959 lb/hr.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from historic (protocol) pre-control baseline and post-control average hourly emission rates representing the visibility impairment impact reduction for LOS Unit 2. Three post-control CALPUFF model runs for LOS Unit 2 were conducted with the same presumptive BART SO_2 emission baseline rate of 95%, constant PM emissions, and various levels of NO_X control assuming the same boiler design rating for heat input (5,130 mmBtu/hr). For the three post-control alternatives representing LOS Unit 2 PTE annual emissions associated with the future PTE case, the model used average unit NO_X emission rates of 0.48, 0.304, and 0.265 lb/mmBtu (corresponding to the design parameter in Table 1.2-1 and control rates in Table 1.4-1) multiplied by the boiler heat input rating of 5,130 mmBtu/hr to yield average hourly NO_X emission rates 2,462, 1,560, and 1,360 lb/hr. The boiler heat input basis for LOS Unit 2's historic highest 24-hour pre-control NO_X emission baseline, in keeping with the NDDH BART visibility impairment impact modeling protocol, is different than assumed for the PTE annual post-control conditions of the NO_X control alternatives evaluated for visibility impairment impacts.

The results of the visibility impairment modeling at the historic pre-control (protocol) baseline NO_X emission rate for LOS Unit 2 showed that all four of the designated Class 1 areas exceeded 0.5 deciView for highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Lostwood National Wildlife Refuge (LNWR) showed the biggest predicted visibility impairment impact, which averaged 0.98 dV for the three years modeled (2000-2002). Average predicted visibility impairment impacts decreased significantly with presumptive BART SO_2 emission rate combined with constant PM emissions and various post-control ASOFA-enhanced NO_X emission rates for LOS Unit 2. This is shown in Table 2.5-10.

TABLE 2.5-10 – Average Visibility Impairment Impacts from Emission Controls – LOS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)			
	Historic Pre-Control Baseline	PTE Emissions, ASOFA[2]	PTE Emissions, SNCR w/ ASOFA[2]	PTE Emissions, RRI+SNCR w/ ASOFA[2]
TRNP-South Unit	0.807	0.221	0.158	0.143
TRNP-North Unit	0.756	0.180	0.139	0.129
TRNP-Elkhorn Ranch	0.535	0.120	0.093	0.087
Lostwood NWR	0.979	0.285	0.206	0.191

(1) - Average 90^{th} percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

Analysis of the reduction in visibility impairment impact included a comparison of the emission controls' effectiveness of reducing predicted visibility impairment impacts for the conditions of the future PTE case operation of LOS Unit 2 versus the historic pre-control (protocol) baseline that was modeled. LNWR again showed the highest average predicted visibility impairment impact reduction resulting from LOS Unit 2 emissions controls during PTE (future PTE case) heat inputs versus historic pre-control baseline emissions. These comparisons are shown in Table 2.5-11.

TABLE 2.5-11 –Average Visibility Impairment Impact Reductions From Emission Controls – LOS Unit 2 (vs Historic Maximum 24-Hour Average Hourly Emission Baseline)

Federal Class 1 Area	Visibility Impairment Reductions[1] (deciView)		
	PTE Emissions, ASOFA[2]	PTE Emissions, SNCR w/ ASOFA[2]	PTE Emissions, RRI+SNCR w/ ASOFA[2]
TRNP-South Unit	0.586	0.649	0.664
TRNP-North Unit	0.577	0.617	0.628
TRNP-Elkhorn Ranch	0.415	0.441	0.447
Lostwood NWR	0.694	0.773	0.788

(1) - Difference of average 90^{th} percentile predicted post-control visibility impairment impact versus historic pre-control (protocol) baseline visibility impairment impact. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

The comparison in Table 2.5-12 shows the reduction of average visibility impairment impact from LOS Unit 2 NO_X emissions expected to result from ASOFA combined with SNCR with and without RRI relative to the average visibility impairment impact from post-control ASOFA NO_X emission rates applied to LOS Unit 2.

TABLE 2.5-12 – Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission Visibility Impairment Impact)

Federal Class 1 Area	Incremental Visibility Impairment Impact Reductions, from NO_X Emission Controls[(1)]	
	PTE Emissions, SNCR w/ ASOFA (dV)	PTE Emissions, RRI+SNCR w/ ASOFA (dV)
TRNP-South Unit	0.063	0.078
TRNP-North Unit	0.040	0.051
TRNP-Elkhorn Ranch	0.027	0.033
Lostwood NWR	0.079	0.094

(1) - Incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

This analysis included a determination of the cost-effectiveness of reducing predicted visibility impairment impact for a particular NO_X emission rate associated with the control alternatives evaluated on LOS Unit 2. The basis of comparison was the average predicted visibility impairment impact and estimated levelized total annual cost (LTAC) for the advanced form of separated overfire air (ASOFA) alone under the future PTE case conditions. The estimated additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) relative to the LTAC from post-control ASOFA NO_X emission rates applied to LOS Unit 2 are shown in Table 2.5-13.

TABLE 2.5-13 – LTAC for NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC)

Incremental LTAC Change for NO_X Emission Reduction(1)	
PTE Emissions, SNCR w/ ASOFA ($/yr)	**PTE Emissions, RRI+SNCR w/ ASOFA ($/yr)**
8,460,000	13,230,000

(1) - Incremental Levelized Total Annual Cost for NO_X control alternatives compared to ASOFA for PTE heat input rate (future PTE case). All cost figures in 2005 dollars. See Table 2.5-8 for details.

The comparison in Table 2.5-14 shows that the additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) divided by the additional average predicted visibility impairment impact reduction relative to the post-control ASOFA NO_X emission rates and LTAC applied to LOS Unit 2 would result in hundreds of millions of dollars per deciview of control cost visibility impairment impact effectiveness.

TABLE 2.5-14 – Cost Effectiveness for Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC and Visibility Impacts)

	Incremental Visibility Impairment Reduction Unit Cost, from NO_X Emission Controls(1)	
Federal Class 1 Area	**PTE Emissions, SNCR w/ ASOFA ($/deciView-yr)**	**PTE Emissions, RRI+SNCR w/ ASOFA ($/deciView-yr)**
TRNP-South Unit	135,000,000	183,000,000
TRNP-North Unit	210,000,000	279,000,000
TRNP-Elkhorn Ranch	317,000,000	436,000,000
Lostwood NWR	108,000,000	152,000,000

(1) - Incremental Levelized Total Annual Cost divided by incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). All cost figures in 2005 dollars.

The number of days predicted to have visibility impairment due to LOS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) NO_X, SO_2, and PM emission rates described previously in this Section. The results were summarized and presented in Table 2.4-15. Similarly, the same information for the post-control SO_2 and PM alternatives with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 2.5-16. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between post-control SO_2 and PM alternatives with SNCR with ASOFA-controlled and RRI+ SNCR with ASOFA-controlled NO_X emission rates versus ASOFA-controlled NO_X emission rates are summarized and shown in Table 2.5-15.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2002 for TRNP's South Unit. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the pre-control model results is included in Section 3.5. The pair of post-control SO_2 and PM alternatives combined with SNCR with ASOFA or RRI+SNCR with ASOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same pair of post-control SO_2 and PM conditions with ASOFA-controlled NO_X emission rates. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the RRI+SNCR with ASOFA-controlled PTE emission rates and SNCR with ASOFA-controlled PTE emission rates compared to ASOFA NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.5-5, 2.5-6, and 2.5-7.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.5 SUMMARY OF IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

Table 2.5-16 summarizes the various quantifiable impacts discussed in Sections 2.5.1 through 2.5.4 for the NO_X control alternatives evaluated for LOS Unit 2.

Table 2.5-15 – Visibility Impairment Improvements – Post Control vs ASOFA NO_X Control with SO_2 and PM Controls LOS Unit 2

Class 1 Area	NO_X Control Technique w/ SO_2 Control Level(1)	Visibility Impairment Reduction(2) (ΔdV)	ΔDays(3) Exceeding 0.5 dV in 2000	ΔDays(3) Exceeding 0.5 dV in 2001	ΔDays(3) Exceeding 0.5 dV in 2002	ΔDays(3) Exceeding 1.0 dV in 2000	ΔDays(3) Exceeding 1.0 dV in 2001	ΔDays(3) Exceeding 1.0 dV in 2002	ΔConsecutive Days(3) Exceeding 0.5 dV 2000	ΔConsecutive Days(3) Exceeding 0.5 dV 2001	ΔConsecutive Days(3) Exceeding 0.5 dV 2002
TRNP South	RRI+SNCR w/ ASOFA	0.078	4	8	9	2	2	8	0	1	0
	SNCR w/ ASOFA	0.063	3	7	6	2	2	7	0	1	0
TRNP North	RRI+SNCR w/ ASOFA	0.051	6	8	4	2	2	8	0	0	0
	SNCR w/ ASOFA	0.040	4	6	4	2	2	6	0	0	0
TRNP Elkhorn	RRI+SNCR w/ ASOFA	0.033	2	3	3	0	1	2	0	1	0
	SNCR w/ ASOFA	0.027	2	2	3	0	1	2	0	1	0
Lostwood NWR	RRI+SNCR w/ ASOFA	0.094	12	10	6	5	7	2	0	0	1
	SNCR w/ ASOFA	0.079	9	6	6	5	5	2	0	0	1

(1) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - Difference in average predicted visibility impairment impacts (90th percentile) for 2000-2002 for alternatives' post-control NO_X emission levels versus ASOFA-controlled NO_X emission level with same PTE heat input SO_2 and PM post-control alternatives' emission rate (future PTE case).

(3) - Difference in number of days is 100th percentile level for predicted visibility impairment impacts provided in Appendix D1.

Figure 2.5-5 – Days of Visibility Impairment Reductions – 0.5 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

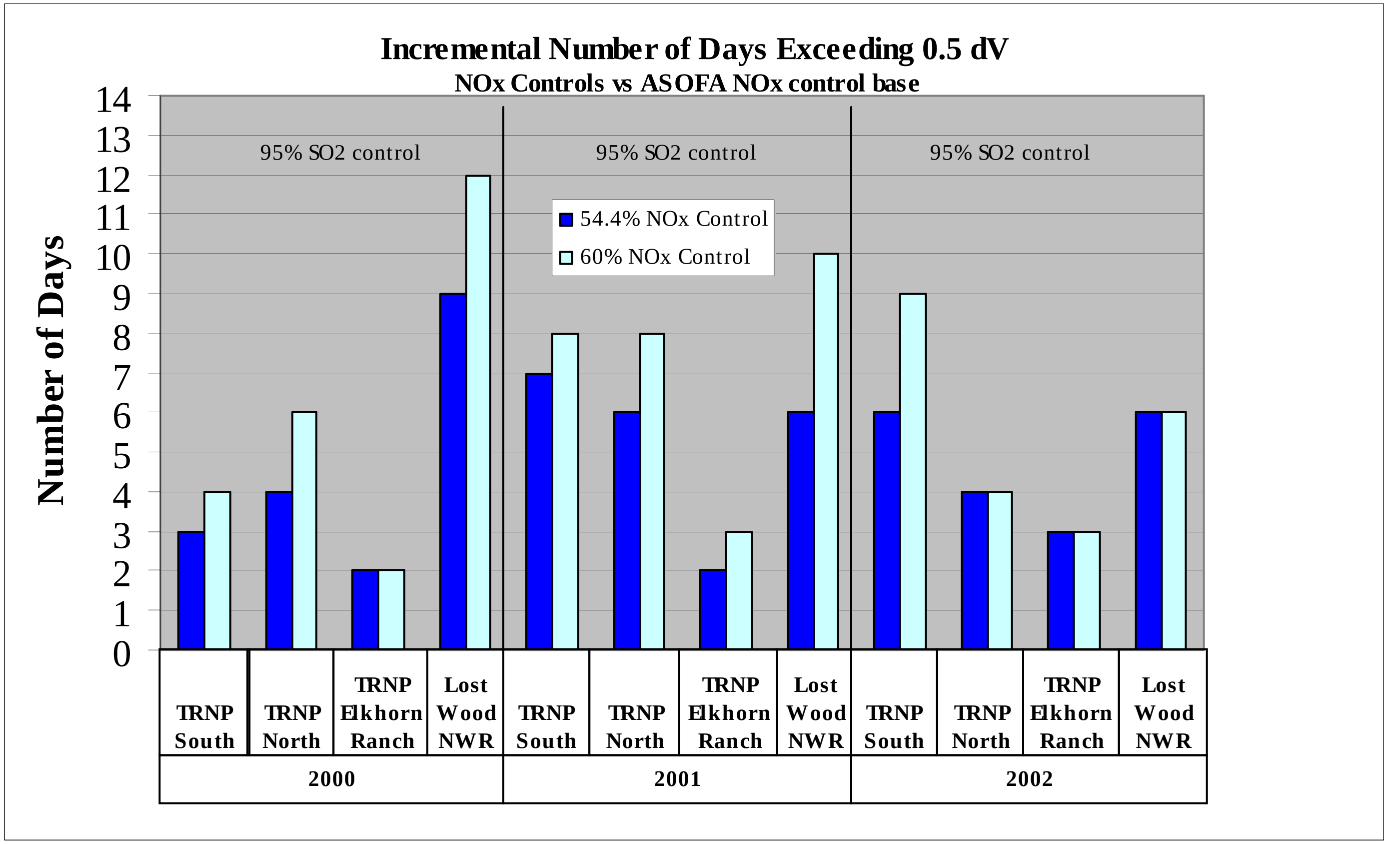

Figure 2.5-6 – Days of Visibility Impairment Reductions – 1.0 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

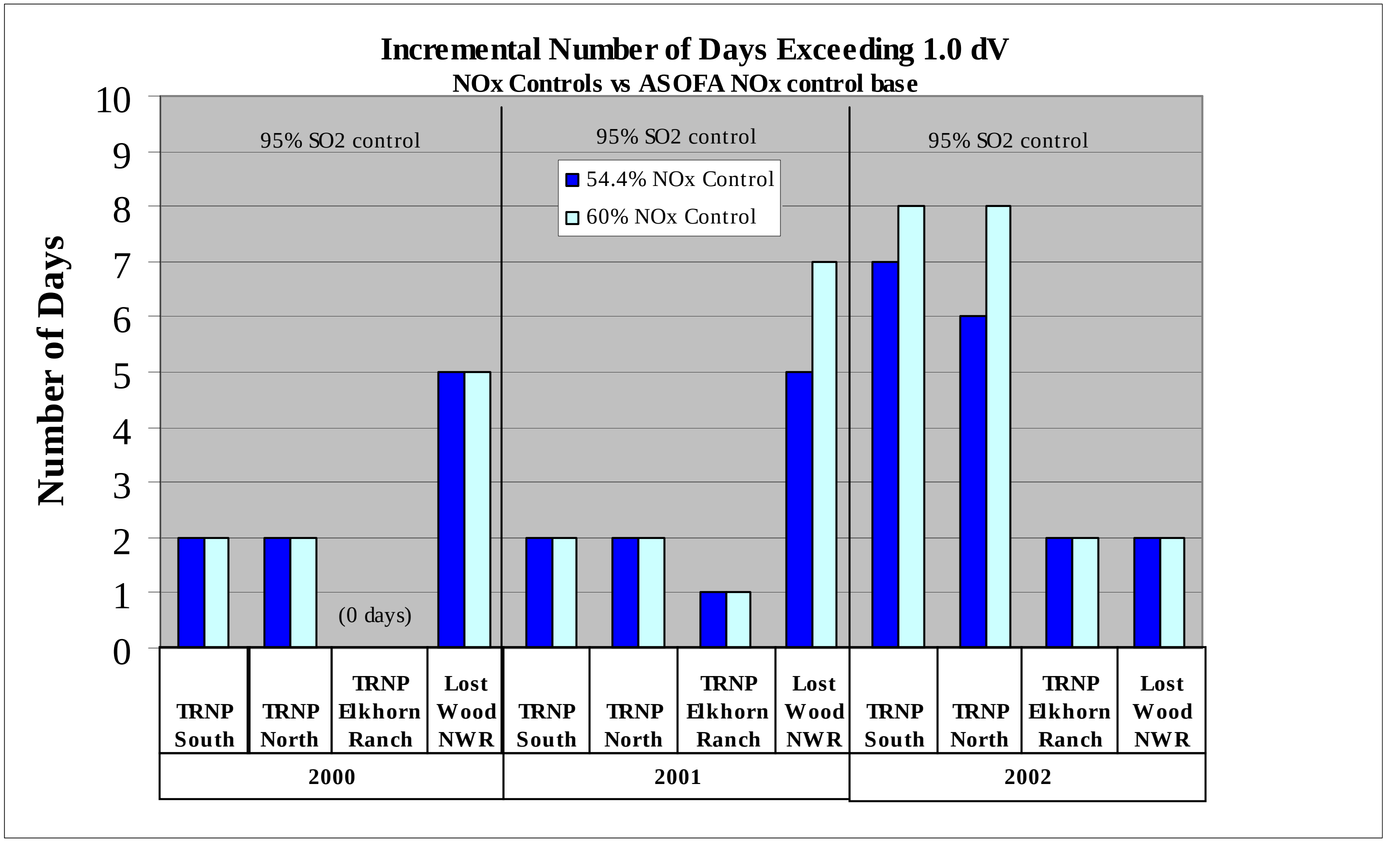

Figure 2.5-7 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

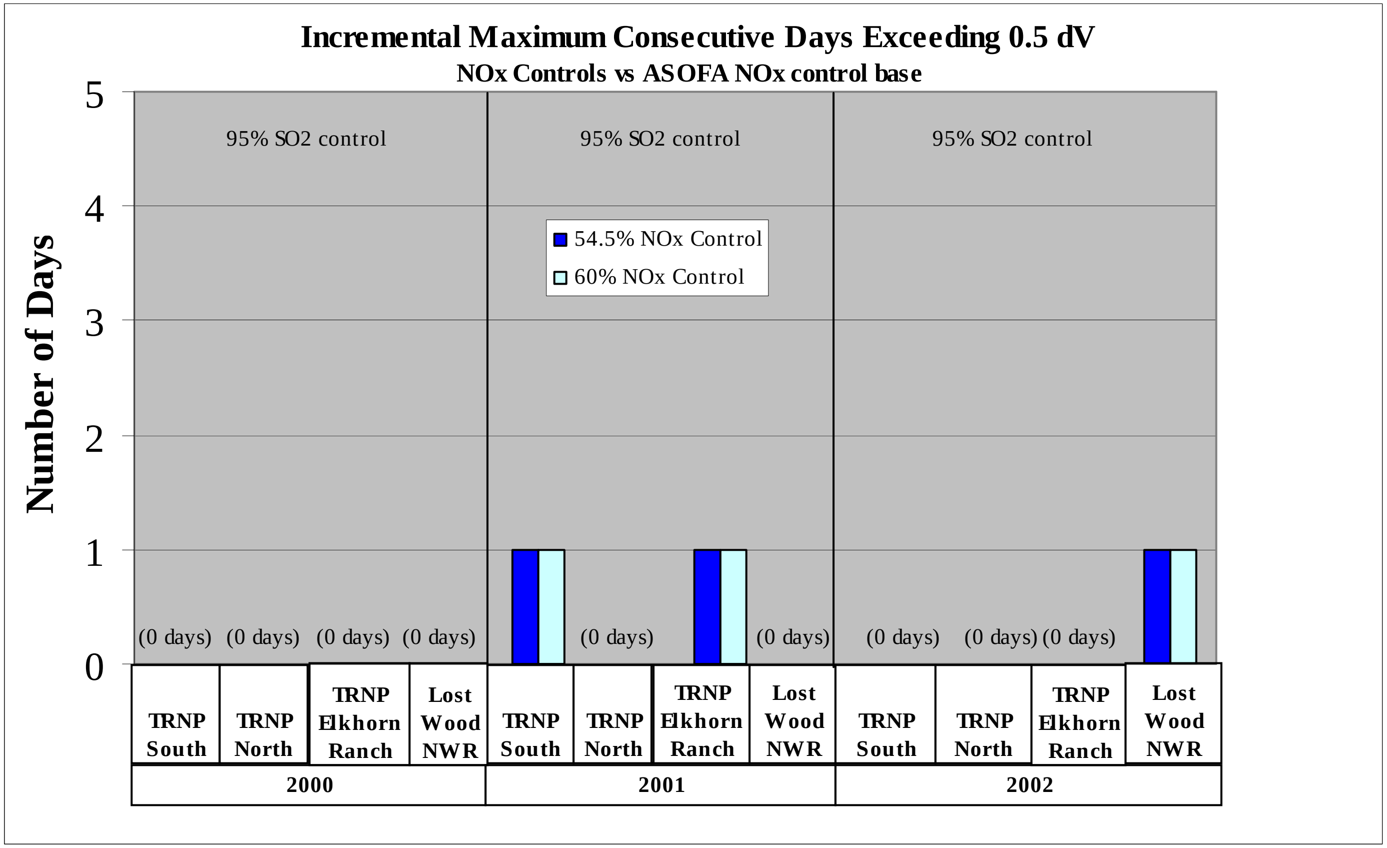

Table 2.5-16 – Impacts Summary for LOS Unit 2 NO_X Controls (vs Pre-Control PTE NO_X Emissions)

NO_X Control Technique w/ SO_2 Alternative	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction: Class 1 Area	Visibility Impairment Impact Reduction: Incremental(2) ΔdV	Incremental Visibility Impairment Reduction Unit Cost(1),(3) ($/dV-yr)	Energy Impact (kW)	Non Air Quality Impacts
RRI+SNCR w/ ASOFA	60.3%	9,094	13,230,000	1,680	TRNP-S	0.078	183,000,000	284	Flyash unburned carbon increase, ammonia in flyash
					TRNP-N	0.051	279,000,000		
					TRNP-Elk	0.033	436,000,000		
					LNWR	0.094	152,000,000		
SNCR w/ ASOFA	54.5%	8,226	8,460,000	1,160	TRNP-S	0.063	135,000,000	155	Flyash unburned carbon increase, ammonia in flyash
					TRNP-N	0.040	210,000,000		
					TRNP-Elk	0.027	317,000,000		
					LNWR	0.079	108,000,000		
ASOFA	28%	4,193	1,060,000	254	TRNP-S	base	base	1	Flyash unburned carbon increase
					TRNP-N	base	base		
					TRNP-Elk	base	base		
					LNWR	base	base		

(1) - All cost figures in 2005 dollars.

(2) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) from PTE post-control NO_X emission levels relative to ASOFA post-control NO_X emission levels; all cases have 95% control SO_2 emission level and same PM post-control level at 5,130 mmBtu/hr heat input and 8,760 hours per year operation for the future PTE case, for 2000-2002.

(3) - Incremental LTAC for RRI+SNCR w/ ASOFA = \$13,230k/yr; SNCR w/ ASOFA = \$8,460k/yr; vs ASOFA = \$0k/yr (base), divided by incremental ΔdV. See Table 2.5-14 for details.

NO_X SECTION REFERENCES:

(see pages 127 -131 in the August 2006 BEPC BART Determination Study final draft report)